PETROLEUM PRODUCTION ENGINEERING

BY

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PREFACE

While the petroleum industry largely owes its present state of development to economic geologists and to representatives of the mining, civil, mechanical, electrical and chemical engineering professions, it is generally recognized that a collegiate curriculum in either of these primary branches of engineering leaves the training of the engineer deficient in one phase or another of the technology of petroleum production. With the purpose of preparing engineering students for participation in all phases of the petroleum industry, several of the American universities and engineering schools have assembled specialized curricula in petroleum engineering, comprising groups of selected courses extending over four or more years. Wherever introduced, the movement has met with popular response on the part of students and of engineers and others interested in the development of the petroleum industry. In the near future, this industry promises to require the services of many engineers trained both academically and practically to a proper understanding of its specialized problems.

The writer's principal purpose in preparing this book has been to provide a text or work of primary reference for petroleum engineering students in that part of their curriculum which pertains to the technology of oil field development and petroleum production. The manner of presentation of the data closely follows that developed by the author in the conduct of courses in petroleum production engineering in the University of California.

The literature of this field is abundant but widely scattered, much of the best material being unobtainable to one lacking the facilities of a comprehensive technical library. In the present volume, an effort has been made to bring together the more important information bearing on each phase of the oil-producing industry, and to interpret the major facts in terms of the requirements of individuals interested in the whole rather than in the special subdivisions thereof.

The field of the petroleum engineer is not as yet well defined. There are those who consider that the petroleum engineer should be one competent to participate in any phase of the oil industry; others would apply the term only to those engaged in the engineering aspects of petroleum production, reserving petroleum refining to the chemical engineer, and the exploration for new oil deposits to the "petroleum geologist." The natural gas industry is very closely related to the petroleum industry; the oil shale industry of the future promises to bear an intimate relationship. Popular opinion has apparently not as yet determined whether or not these activities belong within the field of the petroleum engineer.

However this may be, the writer believes that he expresses the sense of a majority of those engaged in the oil industry in recognizing in petroleum production engineering a field distinct from that of the petroleum geologist on the one hand and from that of the petroleum refiner on the other. The present work therefore touches but lightly upon the science of petroleum exploration and prospecting. Chapter I is provided merely to review those aspects of petroleum geology which are essential to a proper understanding of the later chapters. Excellent books covering the technology of this field are already available. Chapter XVIII, also, sketches merely in outline the technology of another closely related industry: petroleum transportation, the connecting link between the field of the oil producer and that of the refiner. The technology of natural gas production and its utilization in the extraction of natural-gas gasoline, while recognized as very closely identified with the production of petroleum, is nevertheless regarded as a distinctly separate and more specialized field.

Detailed acknowledgment of all sources of information drawn upon in the compilation of the text would be impossible within the brief space here afforded, but an effort has been made to indicate the more important works of reference by a system of superior figures inserted throughout the text. These figures refer to similarly numbered items in the bibliographies given at the end of each chapter. Where more direct extracts from the literature have been used, footnotes indicate the source. Publications of the U. S. Bureau of Mines are especially prolific sources of information, which have been freely drawn upon. The writer is also indebted to the Union Tool Company and to the California National Supply Company, manufacturers of oil well drilling tools and equipment, for aid in the preparation of many of the illustrations used. Above all, the author is indebted to the University of California for the use of research, library and other facilities, and for the many unusual opportunities for field observation that have been his privilege by reason of his association with its faculty.

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CONTENTS

PETROLEUM PRODUCTION ENGINEERING

CHAPTER I

PETROLEUM EXPLORATION AND PROSPECTING

The discovery of oil deposits as a result of exploration and prospecting is a phase of the petroleum engineer's work that requires a broad training in all the geological sciences as well as a thorough knowledge of the nature of petroleum, its origin and the manner in which it reacts under the influence of earth forces. While many of the world's oil fields have been discovered accidentally, or by fortuitous methods involving little or no knowledge of geology, it is universally recognized today that this science—particularly that branch of it known as "structural geology and stratigraphy"—offers the only key to nature's undiscovered petroleum reserves. The petroleum geologist is becoming a specialist, already recognized by many as a member of a profession almost distinct from that of the petroleum engineer; but in a broader view, petroleum geology is essentially a part of, or at any rate very closely allied with, petroleum engineering, and it is impossible to draw any sharp line of distinction between them.

PHYSICAL PROPERTIES AND CHEMICAL CONSTITUTION OF PETROLEUM

The prospector for petroleum must first of all become thoroughly acquainted with the nature of the substance which he seeks, so that he may recognize it when it is encountered in any of its various forms, or when it is present only in minute traces.

Varieties and Forms of Petroleum.—Petroleum is a mixture of naturally occurring hydrocarbons which may assume either the solid, liquid or gaseous state. These three phases of petroleum are transmutable, one into the other, by the application of moderate changes in temperature and pressure. Some of the constituents of petroleum are solids at ordinary earth temperatures, but the application of heat to produce a slight rise in temperature will cause them to assume liquid form; and further heating to the boiling point will convert them into gases and vapors. Other constituents are vapors at ordinary temperatures, but earth pressures naturally developed within the containing rocks will cause them to condense, forming liquids. Relief of this pressure will

permit the liquid to vaporize again, providing the temperature does not change. Liquid petroleum may also be converted into the solid or gaseous states by evaporation of the lighter and more volatile fractions, the latter forming gases or vapors, and the heavier fractions forming solids. The solid and gaseous forms are soluble in the liquid forms. Chemical changes, such as oxidation of the liquid petroleum, may also be instrumental in causing solidification.

In nature, all gradations ranging from hard brittle solid forms, through soft waxy substances, viscous semisolids, heavy viscous liquids, light volatile liquids of water-like consistency, and heavy vapors, to light, almost uncondensable gases, may be found associated in the same deposit. As pressure, temperature and other physical and chemical changes occur, there will be continual readjustment between the different phases of associated hydrocarbons. Filtration of liquid petroleum through clays and other close-grained rocks within the earth may also bring about segregation of different constituents. It seems probable that most mineral waxes are either oxidation products derived from liquid petroleum, or residual products resulting from evaporation or segregation of the more volatile constituents. Gaseous hydrocarbons, which are always associated with liquid petroleum, are in many cases derived directly from the latter by evaporation or natural distillation; or, the two, having a common origin, may accompany each other throughout their subsequent migration and accumulation.

Chemical Composition and Constitution of Petroleum.—Chemically, petroleum consists of a mixture of hydrogen and carbon, the ultimate composition usually showing from 11 to 13 per cent of the former and 84 to 87 per cent of the latter. Sulphur, nitrogen and oxygen, the more important impurities, are often present to the extent of 1 per cent, and occasionally to 4 per cent or even more. Helium has also been found as a constituent of some natural gases associated with liquid petroleum. While the elemental constitution of petroleum is fairly uniform, the molecular constitution will vary within wide limits. As many as 18 different series of hydrocarbons have been identified in various crude petroleums, with numerous individual representatives of one or more of these series ordinarily present. An examination of Table I will give the reader some idea of the great variety of combinations of hydrogen and carbon that have actually been identified in petroleum.* Doubtless there are many more which have not as yet been isolated.[2]

*Compiled from the work of Clarke, Mabery and others, by J. H. G. Wolf.

TABLE I.—CHEMICAL CONSTITUTION OF PETROLEUM

Name and group formula of series	Individual hydrocarbon compounds: Name	Individual hydrocarbon compounds: Composition	Form under ordinary conditions	Remarks
Paraffins (C_nH_{2n+2})	1. Methane	CH_4	Gaseous	These hydrocarbons may be further subdivided into a number of isomeric series—the primary, secondary and tertiary paraffins which, with equal percentage composition, differ in physical properties owing to differences of atomic arrangement within the molecules. This series is present in practically all petroleums, but preponderates in oils of "paraffin base," such as those of Pennsylvania. Lighter members of the series, gases and liquids, are those generally associated with asphalt base oils. The gases carry vapors of the liquid forms at all times. Natural gas is composed almost exclusively of the gaseous members of this series. Hydrocarbons of this series contain the highest percentage of hydrogen and are the most stable.
	2. Ethane	C_2H_6	Gaseous	
	3. Propane	C_3H_8	Gaseous	
	4. Butane	C_4H_{10}	Gaseous	
	5. Pentane	C_5H_{12}	Liquid	
	6. Hexane	C_6H_{14}	Liquid	
	7. Heptane	C_7H_{16}	Liquid	
	8. Octane to	C_8H_{18}	Liquid	
	16 Hexadecane	$C_{16}H_{34}$	Liquid	
	18 Octadecane	$C_{18}H_{38}$	Solid	
	20. Eicosane to	$C_{20}H_{42}$	Solid	
	35. Pentatriacontane	$C_{35}H_{72}$	Solid	
Olefines (C_nH_{2n}) Polymethylenes ($C_nH_{2n})_x$ (Originally called Napthenes)	Ethylene	C_2H_4	Gaseous	These hydrocarbons are relatively unsaturated and constitute the so-called "open-chain" hydrocarbons. They include several independent series, differing in physical and chemical characteristics although identical in percentage composition. One of these, the olefine series, is relatively unstable. They have been identified in Canadian oils. The polymethylenes are relatively persistent and occur in California and Russian oils. They predominate in most oils of asphalt base.
	Propylene	C_3H_6	Gaseous	
	Butylene	C_4H_8	Gaseous	
	Amylene	C_5H_{10}	Liquid	
	Hexylene	C_6H_{12}	Liquid	
	Eicosylene	$C_{20}H_{40}$	Liquid	
	Cerolene	$C_{27}H_{54}$	Solid	
	Molene	$C_{30}H_{60}$	Solid	
Acetylenes (C_nH_{2n-2})		$C_{12}H_{22}$	$C_{19}H_{36}$	Lower members of this series have not been found in petroleum. Higher members are characteristic of oils from Texas, Louisiana, Ohio and some California fields.
		$C_{14}H_{26}$	$C_{21}H_{40}$	
			$C_{22}H_{42}$	
		$C_{16}H_{30}$	$C_{24}H_{46}$	
Turpenes (C_nH_{2n-4})		$C_{23}H_{42}$		Higher members of this series are found generally in small amounts in all crudes of low specific gravity, particularly in Ohio, Texas and California oils.
		$C_{24}H_{44}$		
		$C_{25}H_{46}$		
Benzenes (C_nH_{2n-6}) (Aromatic Hydrocarbons)	Benzene	C_6H_6		Found in all crude petroleums in small amounts Particularly in East Indian, Roumanian and California oils.
	Toluene	C_7H_8		
	Xylene	C_8H_{10}		
	Cumene	C_9H_{12}		
	Cymene, etc.	$C_{10}H_{14}$		

Higher Series: The series (C_nH_{2n-8}) and (C_nH_{2n-10}) are rarely found in petroleum, but occur in small amounts in heavy California and Russian oils. Naphthalene ($C_{10}H_8$), found in Rangoon, Russian and California oils, is probably the only member of the (C_nH_{2n-12}) series that has been positively identified. In all, 18 series (to C_nH_{2n-32}) have been identified in crude petroleum.

Paraffin and Asphaltic "Base" Petroleums.—The difficulty of classifying petroleums by the chemical constitution of the hydrocarbon compounds present in such complexity has led to the general use of a simpler and less technical classification. A main line of distinction is drawn between what are called "paraffin base oils" and "asphaltic base oils." Paraffin oils yield, on reduction to low temperatures, an appreciable proportion of light-colored wax containing chiefly members of the paraffin series. This wax is not readily attacked by acids, or by ether, chloroform, carbon bisulphide or other solvents in which solid hydrocarbons are commonly soluble. Asphaltic oils on slow distillation yield a dark asphaltic residue, usually jet black in color, lustrous and with a well-developed conchoidal fracture. Asphalt thus formed is readily attacked by the stronger acids, and dissolves in the above-mentioned solvents. Hydrocarbons of the polymethylene (naphthene) series predominate in most asphaltic oils. It must not be assumed that a very distinct line can be drawn between the so-called paraffin and asphaltic oils; the terms are used mainly for convenience in a broad classification. Nearly all asphaltic oils contain traces of solid paraffins and many essentially paraffin oils contain asphaltic products. Some petroleums are apparently of "mixed base," responding to the tests suggested for both paraffin and asphaltic oils in equal degree. Probably the best example of a typical paraffin base oil is that produced in Pennsylvania. Most California, Mexican and Russian petroleums are of asphaltic base. Certain oils produced in Oklahoma, Texas and Mexico are of the mixed base type.

In nature's laboratory, hydrocarbons of one type may, by chemical readjustments of the hydrocarbon molecule, or by interaction with other substances, be converted into hydrocarbons of other types. For example, under certain conditions, paraffin base oils may be broken down by the action of gypsum or gypsum-bearing waters, into asphaltic oils.

Properties of Liquid Petroleum.—Commonly, petroleum occurs in the liquid phase, as an oil somewhat lighter and more viscous than water, varying in color from black, through various shades of brown and green to a light amber; or, in rare instances, it may be almost colorless. It has a distinctive odor, sometimes described as "aromatic," resembling that of gasoline, one of the more volatile constituents. The odor is often disagreeable, particularly if the oil is contaminated with sulphur or nitrogen compounds. Liquid petroleum has a peculiar property of reflecting light, developing bluish or greenish color effects, known as "bloom," which are not in evidence when the liquid is viewed by transmitted light. Liquid petroleum spread in a thin film on a water surface also develops a characteristic iridescence. Table II presents the more important physical and chemical characteristics of liquid petroleum.[1]

TABLE II.—PHYSICAL PROPERTIES OF LIQUID PETROLEUM

Property	Remarks
Color	By transmitted light, pale yellow through various shades of red and brown to black. By reflected light, greenish or bluish shades of yellow, red, brown or black.
Refractive index	Measured with Zeiss refractometer, varies from 1.39 to 1.49.
Specific rotatory power.	Measured with Nicol prism, generally ranges between 0° and 1.2°. Occasionally it may rise as high as 3.1°.
Odor	Aromatic; resembling gasoline, coal-tar, oil of cedar, pyridine, etc.
Density.	Specific gravity ranges between .75 and 1.01; Baumé gravity from 56° to 10°−. Generally ranges between .82 and .96 in specific gravity.*
Coefficient of expansion.	Varies from .00036 to .00096; generally between .00070 and .00085 (coefficients for Fahrenheit temperature scale).
Boiling point	Not constant. For different constituents ranges from 68°C. to upwards of 300°C.
Freezing point	Ranges from 60°F. down to temperatures as low as −50°F. (the latter being the specified freezing point for aviation gasoline).
Flash point	−12°C. to 110°C., using open cup tester on a large group of California oils.
Burning point	2°C. to 155°C., using open cup tester on a large group of California oils.
Calorific power	Varies from 15,350 to 22,000 B.t.u. per pound, or from 8,500 to 11,350 calories per gram. Generally ranges between 18,000 and 19,000 B.t.u. per pound.
Specific heat	Ranges between .40 and .52. Averages about .45 for most crudes.
Latent heat of vaporization.	Ranges between 130 and 160 B.t.u. per pound for most paraffin and methylene hydrocarbons.
Viscosity	2.3 to 1,300 Engler for a large group of California oils at 60°F.
Radioactivity	Some of the lighter petroleums display radioactive power, which is thought to have some significance in determining their origin.

* The Baumé scale for liquids lighter than water has the following relation to specific gravity:

$$\text{Specific gravity} = \frac{140}{130 + \text{Degrees Baumé}}$$

This equation, embodying the modulus 140, is endorsed by the U. S. Bureau of Standards. Another Baumé scale using the modulus 141.5 instead of 140, is widely used in the American petroleum industry and has been adopted by the American Petroleum Institute. In oil density measurements, the temperature of the oil should always be 60°F. If measured at any other temperature, corrections in the observed gravity readings must be made.

Properties of Solid Forms of Petroleum.—The naturally occurring solid forms of petroleum include the mineral waxes, paraffin and asphalt. Different varieties of these substances have been given such mineralogical names as Ozocerite, Gilsonite, Grahamite, Elaterite, Alberite, etc. The reader is referred to any of the books on descriptive mineralogy for descriptions of these different varieties of petroleum in solid form.* Table III gives their more important properties.

TABLE III.—PHYSICAL CHARACTERISTICS OF MINERAL WAXES AND RELATED SOLID HYDROCARBONS

Name	Physical properties
Asphaltic Substances	
Albertite	Composition: C = 86.04; H = 8 96, O = 1.97; N = 2.93. Specific gravity = 1.097. Brilliant jet black; pitch-like. Lustrous, conchoidal fracture, slightly fusible in candle flame with intumescence. When rubbed, exhibits static electricity. 4 per cent soluble in ether, 30 per cent in oil of turpentine. Streak, black. Hardness, 1–2.
Grahamite	Specific gravity, 1.145. Color, black; coke-like in appearance. Lustrous on cleavage surfaces Resembles albertite, but is somewhat less lustrous. Displays parallel cleavage and columnar jointing. Completely soluble in chloroform and carbon disulphide. Melts slightly and softens like coking coal at about 400°F. and can be drawn into long threads.
Uintaite or Gilsonite	Composition: C = 80 88; H = 9.76; N = 3 30; O = 6.05. Specific gravity = 1.065 to 1.07. Brilliant, lustrous black. Dark brown streak. Conchoidal fracture Hardness 2–2.5. Fuses in candle flame. Plastic while warm but not sticky. Soluble in turpentine. Electrified by friction. A somewhat similar hydrocarbon, locally called "manjak," is found in Barbados, an island of the West Indies.
Elaterite (Subterranean Fungus)	Composition: C = 85; H = 12; O = 3 Specific gravity = .905 to 1.233. Color: brown, sometimes dark orange red by transmitted light. Subtranslucent. Massive, amorphous. Elastic. Soft, sometimes adhering to fingers. Occasionally hard and brittle. 18 per cent soluble in ether.
Wurtzilite	Specific gravity, 1.030 Black, with brilliant conchoidal fracture. Resembles jet or cannel coal In thin plates, deep red by transmitted light. Amorphous; sectile, shavings somewhat elastic. Hardness 2–3. In boiling water becomes softer, tougher and more plastic Melts and burns in candle flame, giving off bituminous odor. Resists usual solvents Brown streak.
Impsonite	Specific gravity, 1 10 to 1 25 Black; semi-dull luster. Hardness 2-3 Hackly fracture. Insoluble in carbon disulphide. Infusible; decrepitates in flame. Metamorphosed grahamite. 50 to 85 per cent fixed carbon
Paraffin Waxes	
Ozocerite (Natural paraffin)	Composition: C = 85.5; H = 14 5 Specific gravity = .955. Color: yellow-brown, sometimes greenish. Translucent when pure. Wax-like, greasy, foliated; soft, easily indented with thumb nail. Fuses at 56 – 63°F. Completely soluble in ether or carbon disulphide.
Scheererite	Composition: C = 73; H = 24 Specific gravity, 1.0 to 1.2. Color: white, gray, yellow, green or pale red. Translucent to transparent. Pearly or resinous luster. Monoclinic crystals, usually thin and tabular; sometimes acicular Also occurs as crystalline grains and folia. Soft. Melts at 44°C. Soluble in alcohol or ether; also in H_2SO_4 and HNO_3. Burns easily and without residue, emitting feeble aromatic odor. Associated with coal deposits and fine fossils
Hatchettite (Mountain tallow)	Composition: C = 85 55; H = 14 45 Specific gravity, .916 to .983. Color: yellowish-white, wax-yellow, greenish-yellow; blackens on exposure Subtransparent to translucent, but becomes opaque on exposure Glistening, pearly luster. Thin plates, sometimes massive. Soft, greasy, wax-like. Melting point, 46°C. Sparingly soluble in boiling alcohol or in cold ether. Decomposed and charred by boiling concentrated H_2SO_4

Other less important solid paraffin hydrocarbons include Fichtelite, Hartite and Könlite. These waxes are found in association with coal deposits and are thought to be products of former plant life.

A group of oxygenated solid hydrocarbons, including Succinite, Retinite, Bathvillite, Tasmanite, Dysodile, Pyroretinite, Geomyricite, Geocerite, Idrialite, Rochlederite and Dopplerite, are related mineral waxes not directly derived from petroleum.

* DANA, E. S., "A Textbook of Mineralogy," ed. 1905, pp. 544–545.

Composition and Properties of Gaseous Forms of Petroleum.—Gaseous forms of petroleum, commonly called "natural gas," consist of mixtures of hydrocarbon gases and vapors, the more important of which are methane, ethane, propane, butane, pentane and hexane, all of the paraffin series (C_nH_{2n+2}). Petroleum gases are colorless and possess a petroleum odor which is occasionally masked by the stronger odor of impurities, such as hydrogen sulphide or sulphur dioxide. The presence of water vapor sometimes gives natural gas a white, fog-like appearance. Table IV indicates the composition and properties of a number of typical natural gases.

TABLE IV.—PHYSICAL AND CHEMICAL CHARACTERISTICS OF NATURAL GAS

Source of gas	Sp. gr. air = 1	B.t.u. per cu. ft.	CH_4, per cent	Higher* hydro-carbons, per cent	N_2, per cent	CO_2,† per cent
Average Pennsylvania and West Virginia........	624	1,145	80.85	14.00	4.60	.00
Average Ohio and Indiana.......	.637	1,095	83.60	.30	3.60	.20
Average Kansas	.645	1,100	93.65	.25	4.80	.30
Santa Maria Field, Cal.	.810	1,044	62.70	20.20	1.40	15.50
Coalinga Field, Cal	.660	937	88.00	00	.90	11.10
McKittrick Field, Cal	.850	724	66.20	1.00	2.40	30.40
Sunset Field, Cal.........	.660	934	87.70	.00	1.80	10.50
Fullerton Field, Cal....... .. .	.630	1,100	86 70	9 50	2.10	1.70
Kern River Field, Cal......... ..	660	1,047	84.30	8.00	1.20	6.50
Hogshooter Field, Okla..	.580	1,004	94 30	.00	4 60	1.10
Hogshooter Field, Okla	.910	1,548	23 60	69.70	1.30	2.50
Titusville, Pa.	990	1,765	6.60	91.10	2.30	.00
Caddo Field, La	....	.....	95.00	.. ..	2.56	2.34

* Recorded as ethane (C_2H_6) in most analyses, though in "wet" gases, frequently propane, butane, etc.

† Carbon monoxide, oxygen and hydrogen, recorded in many analyses of natural gas, are probably the result either of contamination of the sample with air or of inappropriate methods of analysis. According to *Bulletin* 88 of the U. S. Bureau of Mines, they are never present in natural gas. The gaseous members of the olefin series are also unusual. Hydrogen sulphide and sulphur dioxide are frequently present as impurities.

Petroleum Not a Mineral.—Since petroleum is a complex substance of varying chemical composition, strictly speaking it is not a mineral. It may be properly spoken of, however, as a mineral substance or as an aggregation of minerals.

Thermal Properties of Petroleum.—All hydrocarbons are inflammable, whether in the solid, liquid or gaseous state, though the solid and heavy, viscous liquid forms are relatively less so, because of the difficulty

of securing admixture with the necessary air to support combustion. The gases are frequently explosive, and the lighter, more volatile liquids, surrounded by an inflammable blanket of their own vapor, are readily ignited and will be completely consumed by the resulting flame. The flashpoint, or that temperature at which inflammable gases are given off; the firepoint, or temperature at which the liquid will burn; and the calorific value are thermal properties which enter as important variables in testing petroleum and petroleum products for specific purposes (see Table II).

Distillation Products of Petroleum.—Distillation is an important physical process to which petroleum is subjected in refining, and in isolating its various components to determine their composition or suitability for different purposes. Since petroleum is a mixture of a large number of substances of varying boiling points, when heat is applied in the distillation process the more volatile constituents of low boiling point are distilled first, and the higher boiling fractions are evolved in succession as their respective boiling points are reached. Natural distillation of petroleum within the earth as a result of high earth temperatures, and variation in the pressure to which it is subjected during natural distillation, may explain in large part the marked differences in physical and chemical characteristics. Because of the difficulty of making chemical analyses of petroleum, it is usual to subject the oil to fractional distillation, reporting as a rough indication of its value for refining purposes, the percentages of distillate obtained between stated boiling points. Table V will give some idea of how typical crudes vary in this respect.

ORIGIN OF PETROLEUM

Though many eminent geologists and chemists have investigated and offered theories and experimental evidence in explanation of the origin of petroleum, the matter is still a subject of scientific controversy.[5] Several of these theories seem to offer a plausible explanation of the source and manner of formation of specific deposits, but apparently none are susceptible of general application.

The various theories that appear in the literature of this subject are usually classified into two groups: the so-called inorganic and organic theories. The former attempt to explain the formation of petroleum as a result of geo-chemical reactions between water or carbon dioxide and various inorganic substances, such as carbides and carbonates of the metals. The organic theories assume that petroleum is a decomposition product of vegetable and animal organisms that existed within certain periods of geologic time. Table VI presents the principal ideas on which a number of the better known theories of each group are based.

TABLE V.—DISTILLATION TESTS OF TYPICAL AMERICAN CRUDE PETROLEUMS*

Source of sample	Density in degrees Baumé	Percentage distilling between temperatures specified, degrees															Carbon residue of residuum
		Up to 50	50 to 75	75 to 100	100 to 125	125 to 150	150 to 175	175 to 200	200 to 225	225 to 250	250 to 275	Below 200	200 to 225	225 to 250	250 to 275	275 to 300	
		Atmospheric pressure										40-mm. vacuum Lubricating stocks					
		Gasoline						Kerosene									
Texas, Humble Field	17.8	..	.			5	9	2.3	4.0	6.6	9.6	7.2	8.4	8.1	8.4	5.3	8.0
Texas, West Columbia Field	19.0	.	..	..		.	.	1.5	3.3	6.9	9.9	7.0	10.4	8.3	7.1	9.6	9.1
Texas, Spindle Top Field	19.7	...		..	.	..	.	1.5	2.2	6.9	11.8	8.6	11.3	8.1	9.1	9.2	9.7
Texas, Goose Creek Field	20.5	..			.	..		1.7	4.5	9.7	15.1	1.9	8.5	7.7	6.0	10.7	6.0
Kentucky, Ragland Pool	25.2	.	.	2.3	1.7	3.0	3.1	2.5	4.0	5.3	6.7	3.3	5.4	5.9	5.7	5.4	17.7
California, Sunset Field	29.5	1	1.4	2.1	4.4	4.8	4.2	4.5	5.0	5.6	8.2	2.3	6.4	5.5	5.4	6.3	16.4
Ohio, Cow Creek Field	31.7	.	1.1	1.5	3.5	4.0	5.2	4.4	4.7	5.2	6.8	4.5	5.9	6.6	6.0	7.1	6.5
Kansas, Augusta Field	31.9	..	..	1.8	4.5	5.8	6.6	5.5	6.3	6.5	7.7	4.2	6.9	6.3	5.1	5.5	10.2
Illinois, Lawrence County	32.2	.	.8	1.2	3.3	5.5	4.5	5.1	4.5	4.8	5.2	2.7	5.3	5.5	5.2	6.0	10.6
Texas, Corsicana Field	33.7			.	2.3	4.0	6.0	7.4	7.8	8.5	7.5	6.5	8.2	6.7	6.6	4.9	9.9
Texas, Somerset Field	34.0	1.4	2.1	4.0	6.0	6.1	5.9	5.5	5.3	5.4	5.8	5.1	5.7	5.2	4.1	4.5	11.8
Arkansas, Eldorado Field	34.4	.		7.4	7.0	5.3	5.1	4.0	3.6	4.1	5.1	5.4	7.1	5.5	5.3	5.6	11.0
Oklahoma, Osage County	35.5	.6	1.4	3.9	5.8	5.3	6.1	5.0	5.7	6.6	6.8	5.6	5.8	6.6	4.8	6.1	5.3
Indiana, Lima District	35.8	6	.8	2.8	5.2	4.9	5.9	5.8	4.8	7.0	7.4	4.1	6.1	5.6	5.3	6.8	6.0
Wyoming, Salt Creek Field	36.5	1.8	1.7	4.7	6.2	5.3	5.5	4.1	4.6	5.3	5.8	4.9	5.9	5.6	5.5	5.8	6.1
Texas, Ranger Field	37.0	..	...	5.4	6.8	6.2	6.1	5.7	6.4	6.7	6.6	5.1	7.0	5.6	5.4	4.5	3.9
Ohio, Corning Crude	37.1	9	1.8	4.1	5.3	5.5	5.4	4.8	5.2	5.5	6.3	4.0	5.7	5.7	4.8	6.3	7.4
Ohio, North Lima	37.7	8	1.5	4.4	6.0	6.3	6.1	5.9	6.0	6.6	6.6	4.0	5.9	5.3	5.4	5.5	6.2
Pennsylvania, Venango County	38.3	4	.7	3.7	6.0	5.0	5.0	3.6	3.9	4.9	7.6	5.5	7.0	6.3	5.9	7.1	2.0
Oklahoma, Cushing Field	39.8	1.5	3.3	3.8	8.7	7.2	6.7	6.3	6.2	6.2	5.6	6.0	5.5	4.9	4.7	4.7	6.8
Louisiana, Caddo Field	41.1	..	3.5	3.8	3.8	6.3	9.7	8.1	9.3	7.0	6.1	4.8	6.3	5.3	4.6	5.2	7.3
Pennsylvania, Green County	41.8	1.1	2.1	3.1	5.7	5.2	5.9	5.9	5.8	6.5	6.4	4.0	6.2	6.5	5.4	6.1	1.6
West Virginia, Maryland grade	42.8	3.3	3.7	5.9	8.2	6.8	6.5	5.8	5.6	6.0	6.4	4.6	4.6	4.5	4.6	4.6	1.4
Pennsylvania, Eureka grade	43.7	2.6	2.9	5.0	7.9	6.9	7.0	5.4	5.6	5.6	6.5	3.6	5.6	4.8	4.8	6.0	2.4

* Tests were made by the U. S. Bureau of Mines—Hempel method in each case. Values for carbon residue of the residuum (last column) are made with the Conradson apparatus and are thought to be indicative of the nature of the oil, *i.e.*, whether paraffin or asphaltic base; and particularly, of its value as a source of heavy lubricants.

Data from U. S. Bureau of Mines, *Reports of Investigations* Nos. 2202, 2235, 2293, 2322, 2364 and 2416, by E. W. Dean and others.

Inorganic Theories Discredited.—The inorganic theories, formerly given popular credence, have in recent years given way to theories based on organic evidence, organic origin being now generally accepted. A number of facts have been responsible for the general discrediting of the inorganic theories. Petroleum is notably absent in the rocks formed during geologic periods in which vulcanism was most active. No one has been able to produce it synthetically. Furthermore, the inorganic compounds assumed to be responsible for its formation are rare in nature.

Organic Theories Plausible.—In the case of the organic theories on the other hand, there is abundant corroborative evidence, both in nature and from the laboratory, that petroleum may be derived from organic materials of either animal or vegetable origin. Petroleum deposits are in some instances found in close relation with coal deposits of known vegetable origin. In other cases, diatoms, foraminifera, algae and other microscopic marine organisms have evidently been the source of petroleum. Carbonaceous shales and sandstones are of widespread occurrence in petroliferous areas and frequently contain sufficient organic material to account for the formation of large deposits of petroleum. The conversion of such organic materials into petroleum has been demonstrated in the laboratory, and has been proved possible under conditions normally prevailing in nature.

It seems probable that transformation of the parent organic material into petroleum has proceeded in the absence of air, in muds, shales and sands along the bottom of shallow lagoons, estuaries, bays and lakes.[1] It has also been suggested that salt water and certain anaerobic bacteria may be essential to the transformation, the former preventing rapid decomposition of the parent material during the transition stage, and the latter converting the waxy, fatty and resinous constituents of animal and plant organisms into hydrocarbons. Various nitrogen and sulphur compounds often found in association with petroleum are considered products of these same biochemical reactions. Temperature and pressure are undoubtedly important physical variables which influence the character of the decomposition products. Probably in many cases petroleum is formed by actual distillation, in porous formations within the earth, of solid hydrocarbons derived from the parent organic material.

Natural Distillation of Petroleum from Solid Carbonaceous Materials. It seems reasonable to assume that the liquid and solid hydrocarbons have been in many cases subjected to earth temperatures sufficiently high to bring about their vaporization.* Some theories assume that the primary hydrocarbon resulting from decomposition of the parent organic material is a solid, conforming in its general characteristics to the "kerogen" present in oil shales. Just as oil is distilled by artificial

* WILLIS, B., Geologic distillation of petroleum, *Trans.*, Am. Inst. Mining & Met. Engrs., 1920.

TABLE VI.—THEORIES ADVANCED IN EXPLANATION OF THE ORIGIN OF PETROLEUM

Name of theory or its originator	Salient features	Evidence
Inorganic Theories		
Berthelot's alkaline carbide theory.	Deep-seated deposits of alkaline metals in the free state react with CO_2 at high temperatures, forming alkaline carbides. These, on contact with water, liberate acetylene which, through subsequent processes of polymerization and condensation, forms petroleum.	Evidence lacking. Neither free alkaline metals nor carbides found in nature.
Mendeleef's carbide theory	Iron carbides within the earth, on contact with percolating waters, form acetylene which escapes through fissures to overlying porous rocks and there condenses	See above. Magnetic iron oxides would also be formed as a product of these reactions. Magnetic irregularities have been noted in the vicinity of some oil fields
Moissan's volcanic theory.	Moissan suggests that volcanic explosions may be caused by the action of water on subterranean carbides.	Small quantities of petroleum noted in volcanic lavas near Etna and in Japan Petroleum also associated with volcanic rocks in Mexico and Java.
Sokolov's cosmic theory	Petroleum considered to be an original product resulting from the combination of carbon and hydrogen in the cosmic mass during the consolidation of the earth.	Small quantities of hydrocarbon occasionally found in meteorites.
Limestone, gypsum and hot water theory.	Reactions between carbonate and sulphate of lime in the presence of water, at temperatures sufficient to dissociate the water, theoretically may form hydrocarbons.	Practically, it has been found impossible to demonstrate this reaction in the laboratory.
Organic Theories		
Englor's animal origin theory	Petroleum formed by a process of putrefaction of animal remains. Nitrogen thus eliminated and residual fats converted by earth heat and pressure into petroleum. Activity of anerobic bacteria thought to play a part in the reactions.	Oils resembling petroleum may be distilled from sediments containing fish remains. Many petroleum deposits associated with marine sediments containing an abundance of foraminifera.
Hofer's vegetable origin theory.	Petroleum formed by decay of accumulated vegetable refuse under conditions which prevent oxidation and evaporation of the liquid products formed.	Deposits of petroleum found in close association with sedimentary deposits containing diatoms, seaweed, peat, lignite, coal and oil shale of known vegetable origin. Oils closely resembling petroleum may be distilled from these substances.

means from such shales, so it is thought liquid petroleum may be formed by natural distillation within the containing rocks. Hydrocarbon vapors, thus formed, could migrate much more readily than the liquid forms to structures favorable for their accumulation. On subsequent cooling to lower temperatures the vapor so accumulated would condense,

forming liquid petroleum. Variation in heat and pressure conditions during this natural distillation process, as well as differences in the character of the parent organic material, would account for variation in the types of oil produced. The entire process, as outlined, is analogous in every way to that practiced in the modern refinery.

Weight is given to this theory by the field evidence obtained from petroleum deposits found in close association with sedimentary strata containing coal. The oil in such cases is clearly a natural distillation product obtained by metamorphism of the coal, the hydrocarbons being driven off, leaving the coal richer in fixed carbon. It is found furthermore, that the degree of metamorphism which the coal has suffered is a reliable indication of the presence or absence of oil in the vicinity. White[6] has shown that in those regions in which the coals are but little altered by dynamic influence, and where they have a low fixed-carbon ratio, the oils are heavy and of low grade. On the other hand, in regions of more advanced alteration, where the coals have a higher fixed-carbon ratio, the oils are correspondingly light and of higher grade. Oil is seldom found in regions where the associated coal deposits contain more than 65 per cent of fixed carbon. Considerable gas and a little oil is found in association with 60 to 65 per cent carbon coals; but the bulk of the oil is found in regions where the coals range between 50 and 55 per cent in fixed carbon.

ACCUMULATION OF PETROLEUM

It is apparent that whatever the theory accepted in explanation of the origin of petroleum, the oil would have been widely scattered through the containing rocks. It must subsequently have been subjected to some agency which would effect a concentration of these disseminated particles before the formation of a deposit of commercial proportions is possible. Since the dimensions of petroleum deposits are relatively small in comparison with the areas over which the small particles of oil were originally formed, it is evident that this "migration" of petroleum may necessitate movements over considerable distances. Petroleum has apparently migrated for distances of a mile or more in certain instances where the source of the oil with respect to the deposit in which it is found, is definitely known. The rocks in which accumulation occurs are seldom those in which the petroleum was formed and accumulations are occasionally found in formations stratigraphically unrelated with those containing the parent material.

NATURAL FORCES WHICH ASSIST IN BRINGING ABOUT MIGRATION AND ACCUMULATION OF PETROLEUM

The forces at work in nature which assist in bringing about migration and accumulation of petroleum include: (1) gas pressure; (2) gravity, in

association with the buoyant force of water resulting from difference in density, or the gravity differential between water and petroleum; (3) hydraulic pressure developed by flowing waters in subterranean channels; (4) earth pressure, the result of diastrophism; and (5) capillarity which, by reason of differences in surface tension between water and petroleum, results in segregation of the two fluids and concentration of petroleum in the more porous rocks.

Gas Pressure.—It has been stated previously in this chapter that natural gas is a universal accompaniment of liquid petroleum. The "fixed" hydrocarbon gases (principally methane and ethane) are probably formed as a product of the same reactions that are responsible for the formation of liquid petroleum. Furthermore, as we have seen, the liquid hydrocarbons have a strong vapor tension, tending to enclose themselves in an atmosphere of their own vapors. This vapor tension increases with temperature so that at temperatures readily attainable within the earth's surface the hydrocarbons constituting petroleum may at times exist only in the vapor phase. Even though subsequent condensation of these vapors should occur, there is always formed as a result of such vaporization, an appreciable percentage of fixed gases which are not condensable under ordinary pressure and temperature conditions. Though these hydrocarbon vapors and gases are somewhat soluble in the liquid hydrocarbons, it is evident that the processes involved could easily account for large volumes of free natural gas in close association with deposits of liquid petroleum. The field evidence confirms this reasoning, gas being always in evidence wherever liquid petroleum is produced—frequently under high pressures and in enormous volumes. Gas pressures as high as a ton to the square inch are sometimes recorded. Individual wells drilled into certain "pools" have had initial productions in excess of 100,000,000 cu. ft. per day, and have averaged many millions of cubic feet per day for long periods of time.

Gas moves with freedom through the interstices of porous rocks. It exerts pressure equally in all directions, and in its effort to flow from high-pressure toward low-pressure areas within the earth, liquid petroleum is carried along with it. The liquid petroleum may be carried as films surrounding gas bubbles, or it may be pushed through the rocks in relatively large volumes ahead of the gas.

Selective Action of Gravity on Rock Fluids. *The Anticlinal Theory.*—Below the level of the water table, where temperature and pressure conditions permit, rocks are generally saturated with water. Movement of gas as well as of liquid petroleum is undoubtedly brought about in many instances by the selective action of gravity on the rock fluids. Inundated globules of oil tend to float in water by reason of their lower density, and accumulate in the upper horizons of the porous strata to which they have access. Such migration is not necessarily vertically upward, movement

up-dip along the under side of an impervious capping often contributing a considerable horizontal component. If we consider the gas pressure and hydrostatic forces at work sufficient to overcome the resistance offered by the rock pores, it is obvious that the oil globules will continue to move up-dip until they are trapped, or until they reach the highest point in the stratum in which they are stored.

Unless the oil-containing stratum is covered by an unbroken, impervious cap rock, the oil will escape to overlying formations until it encounters an impervious stratum. The crests of domes and anticlines serve in this

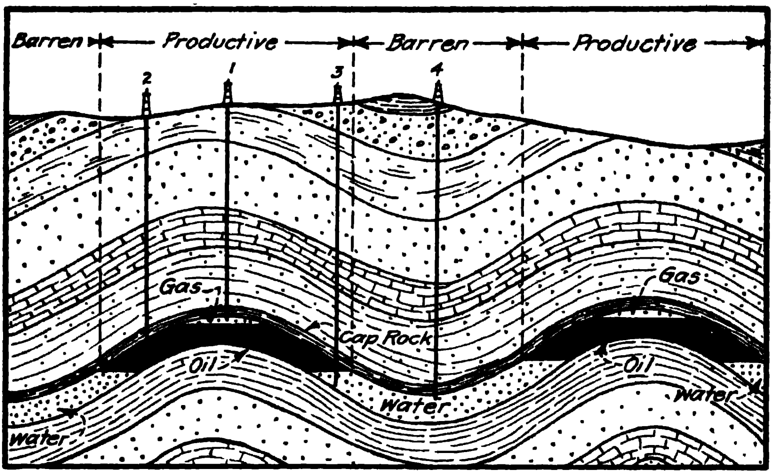


FIG. 1.—Illustrating ideal anticlinal conditions.

The figure shows two productive symmetrical anticlines with intervening barren syncline. Gravitational segregation of gas, oil and water in the anticlinal crests of the oil-bearing stratum has been complete. Well No 1 is a gas well, but No 2 is an oil well, No 3 produces both oil and water; No. 4 is a water well.

way as elevated structural traps in which the oil and gas, under the influence of hydrostatic forces, tend to accumulate (see Fig. 1). Gas being lighter than oil, will tend to accumulate under the influence of these same forces in the upper levels of the anticlinal trap, while oil will occupy an intermediate zone between the gas and the underlying water. So many oil fields show evidence of anticlinal structure, with the major accumulations invariably found at or near the structural crest, that prospectors for petroleum seek first of all areas in which anticlinal structure is in evidence. The "anticlinal theory," embodying the principles just presented, is now universally accepted as the controlling factor in oil accumulation.

Consideration of Fig. 1 will make it clear to the reader that inclination of the strata must have a considerable influence on the effectiveness with which the forces causing migration may operate. The greater the dip

of the formation, the more rapidly will transportation of the oil and gas be effected, and the more complete will be their separation from water and from each other. Other factors, such as rock porosity, gas pressure and gravity and viscosity of the oil, will also influence the rate of migration and the completeness of separation of the rock fluids.

Migratory Ground Waters. *Hydraulic Pressure.*—It is definitely known that meteoric waters are often migratory and flow within the earth's surface in well-defined channels. Such movement, while sluggish, due to the resistance to flow which it must overcome, is persistent, and the water may flow in one direction over long periods of time. It is thought that the carrying effect of ground waters in continual motion in this way may be instrumental in transporting globules of oil. We may think of this as due to hydraulic pressure, a force obviously of quite different character from that developed by hydrostatic forces as described above. Globules of oil flowing in underground water channels may, by reason of their lower specific gravity, be trapped in stagnant anticlinal crests, just as driftwood accumulates in quiet pools along the shore lines of surface streams.

Earth Pressure. *Diastrophism.*—When sedimentary strata are subjected to forces which bring about the formation of anticlinal and synclinal folds, great differences in pressure within the deformed strata must result. The inner portion of a fold is subjected to compression, the outer to tension. Both result in shrinkage of pore space and expulsion of fluids formerly contained within the rock. Diastrophism varies[9] in intensity at different points within the earth's crust, and fluids expelled from rocks in the region of greatest deformity flow toward the areas where folding is less intense and where more moderate pressures prevail. During this expulsion of the rock fluids, water, oil and gas may be forced to migrate and will tend to accumulate in anticlinal crests in much the same manner as in the case of direct hydraulic pressure.

Capillarity.—Water has a surface tension nearly three times that of petroleum; therefore capillarity is proportionately effective in its lifting power. The openings in rocks are, for the most part, of capillary size, and through capillary attraction they exert a selective action on the two fluids, drawing water into the close-grained rocks and displacing petroleum which is forced into the rocks of greater porosity.'[16] While it would appear difficult to explain the extensive migrations of petroleum that have occurred in some instances as due to the operation of differential capillarity, it seems reasonable to assume that this force may be instrumental in effecting local segregations of water and oil. Lenticular segregation of oil in sands may be explained on this basis, and capillarity may assist in forcing petroleum out of the rocks in which it is formed, into more porous rocks, where gas, hydrostatic, hydraulic and earth pressure may be effective in bringing about the major concentrations.[14]

LITHOLOGICAL CHARACTER OF PETROLEUM-BEARING ROCKS AND ASSOCIATED ROCKS

A knowledge of the lithological characteristics of sedimentary rocks will be of value to the prospector in studying both the oil reservoir rocks and the enclosing cap rocks. The first essential condition in the formation of a commercially important deposit is that there must be a porous fractured, cavernous or creviced stratum in which the oil may accumulate, and that this be overlain by an impervious cap rock which prevents escape of the oil after its concentration has been effected.

Oil Reservoir Rocks. *Significance of Porosity.*—Reservoir rocks are usually sands or sandstones, often loosely cemented so that the percentage of voids may range as high as 37 per cent. The average sandstone has a porosity of about 16 per cent. Many oil-producing sands range between 20 and 25 per cent in porosity. Conglomerates, if not too thoroughly cemented, may have porosities as great as sandstones. Dolomitic limestones have porosities as great as 12 per cent, due to replacement of lime with magnesia, and in certain regions serve as important reservoir rocks for the storage of petroleum. Cleavage planes and solution cavities may increase the storage capacity of limestone to as much as 35 per cent. Even close-grained shales with porosities ranging from 2 to 10 per cent have proved commercially profitable as sources of oil in some fields. However, the presence of clay or shale in an oil-bearing rock must, in general, greatly reduce its storage capacity, the argillaceous material filling in between the coarser constituents of sandstone or conglomerate. Cementation is even more effective in reducing porosity. Obviously, the storage capacity of a porous stratum increases directly with its thickness.

High porosity in a granular rock results from uniformity in size and shape of grains, and is independent of the actual size of grain. The arrangement of grains is also an important factor in determining porosity. A sandstone made up of uniform 200-mesh spherical grains has as high a porosity as a similar one of 20-mesh grains. It can be demonstrated mathematically that true spheres of uniform size, packed as closely as possible, have a porosity of 25.95 per cent. If rock particles are spherical, but of assorted sizes and closely packed, the porosity will be less than this. Only when the granular particles are of irregular or angular shape may the porosity be greater than 26 per cent.

While the size of the grain, theoretically, does not influence the storage capacity of a granular rock, the size of the pores between the grains will determine what fluids may enter, and will have a marked influence upon the rate of movement of fluids through the rock. It can be shown experimentally that water follows the ordinary laws of hydraulics only when it flows through openings of greater than capillary size (*i.e.*, tubes greater than .508 mm. in diameter or sheet openings

exceeding .25 mm. in width). In capillary openings water is affected by capillarity and does not circulate freely, due to greater resistance to flow. Water may enter subcapillary openings (*i.e.*, tubes less than .0002 mm. in diameter, or sheet openings less than .0001 mm. wide), but remains fixed under ordinary temperature and pressure conditions, effectively preventing further circulation.[16] Oil is less readily absorbed by rock pores than water. Natural gas, while entering the rock pores more readily than water, may nevertheless be displaced by the latter in a fine-grained sand, due to capillary action.

The minerals present in oil-bearing sands and sandstones are of little significance except as a means of identifying and correlating strata. Quartz, feldspar, chlorite, mica, magnetite, ilmenite, amphibole, monozite and pyrite are common constituents of petroliferous sandstones.

Storage capacity is not measured solely by interstitial pore space, but is also largely influenced by openings of other types. Joint and cleavage planes, vesicular openings, solution cavities, crevices formed by fracturing and angular cavities in brecciated rock masses often serve for the storage of petroleum.[13] Available space for the accumulation of oil in such rock openings varies widely, and is impossible to estimate even though the texture and mineral content of the rock are definitely known.

Impervious Cap Rocks.—Cap rocks overlying productive oil reservoir-rocks are almost invariably argillaceous rocks—clays, shales or marls. Such rocks, in addition to being impervious to oil, are often pliable and do not fracture readily when bent into anticlinal folds. The thickness of the cap rock is often only a few feet, though it must be sufficient to withstand the gas pressure in the underlying oil sand if it is to be effective as an oil retainer.

PHYSICAL AND CHEMICAL EFFECTS OF ASSOCIATED ROCKS ON PETROLEUM

Laboratory investigation has demonstrated that oil filtering through certain types of clays and earths (particularly fuller's earth) undergoes changes in chemical constitution and physical characteristics. Such filtration effects partial decolorization and a certain degree of fractionation. Light-colored, transparent, mobile oils of low specific gravity are thus derived by natural processes from comparatively heavy, viscous and dark-colored crudes. It seems probable also that many of the impurities found in petroleum are accumulated during its migration from scattered points of formation to the reservoir in which it is finally concentrated. Some authorities note an increased percentage of sulphur in the oil in certain regions as it travels farther from the rocks in which it was formed.

GEOLOGICAL STRUCTURES FAVORABLE TO ACCUMULATION OF PETROLEUM

It has been shown that the forces causing migration of petroleum tend to concentrate oil and gas in the upper horizons of folded porous strata, particularly in the crests of anticlines. The prospector is therefore attracted in his search by indications of anticlinal structure in any of its various forms. These include symmetric and asymmetric anticlines, domes, monoclines and terraces.[11] Faults and unconformities are occasionally instrumental in isolating the rock fluids in parts of formations in such a way as to influence the accumulation of petroleum. Lenses of porous rocks in close association with carbonaceous shales offer favorable

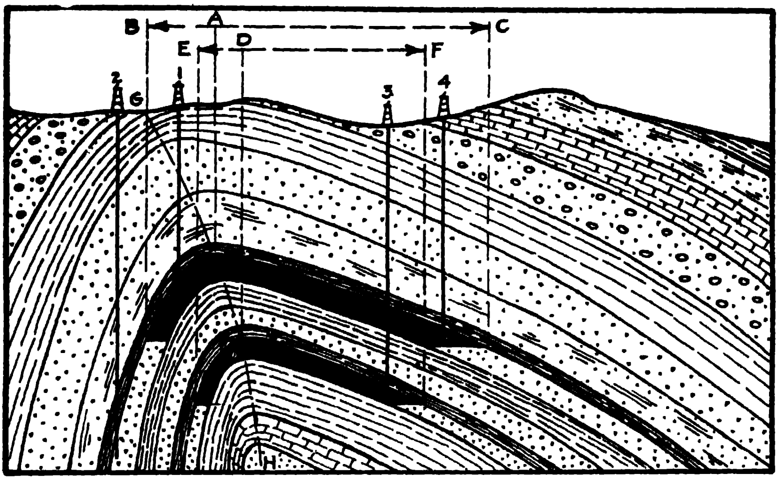


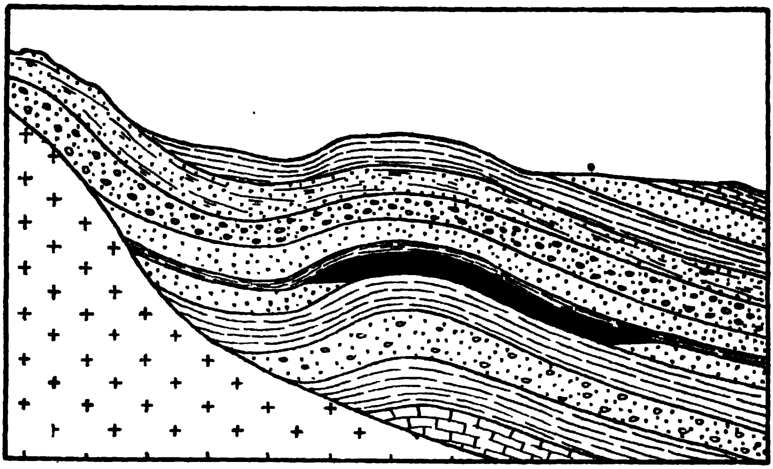
FIG. 2.—Illustrating a simple asymmetric anticline with two oil-bearing strata.

Note change in dip of axis of fold (line *G-H*) *B-C* indicates the width of the productive area for the upper sand, *E-F* that of the lower sand Axes of folds (at *A* and *D*) lie near the left edge of the productive area. Well No. 1 is productive; No 2, only a short distance away, is barren. Well No. 4 produces from the upper sand only, No. 3 from both upper and lower sands.

conditions for oil accumulation. Salt domes and volcanic "necks" have in some fields been responsible for accumulations of petroleum, due to flexuring of strata into which they are intruded. An endless variety of combinations of these structural features present themselves in the geologic study of a prospective oil field.[8]

Anticlines.—Simple symmetrical anticlines, presenting ideal anticlinal conditions for the accumulation of petroleum (see Fig. 1), are seldom found in nature. Usually one flank is steeper than the other, in which case the more common form of asymmetric anticline results (see Figs. 2, 3, 4 and 5); or the axis of the anticline plunges, *i.e.*, is not level (see Fig. 5). A common type of asymmetric anticline, known as "terrace structure" in certain fields, has one flank nearly vertical and the

other inclined at only a few degrees from the horizontal (see Fig. 4). Overturned folds and intense folding may result in exceedingly complex structures, often difficult to interpret from the field evidence (see Fig. 6).[8]



(*After W. H. Emmons*).

FIG. 3.—An asymmetric anticlinal fold along the flanks of a major uplift, illustrating how greater accumulations of petroleum may be found on the basinward side of an anticline. Note difference in level of the edge-water lines on opposite flanks of the anticline.

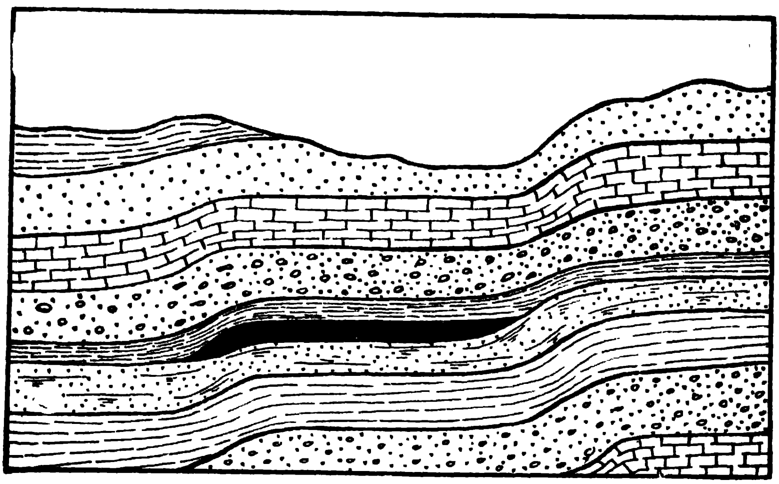
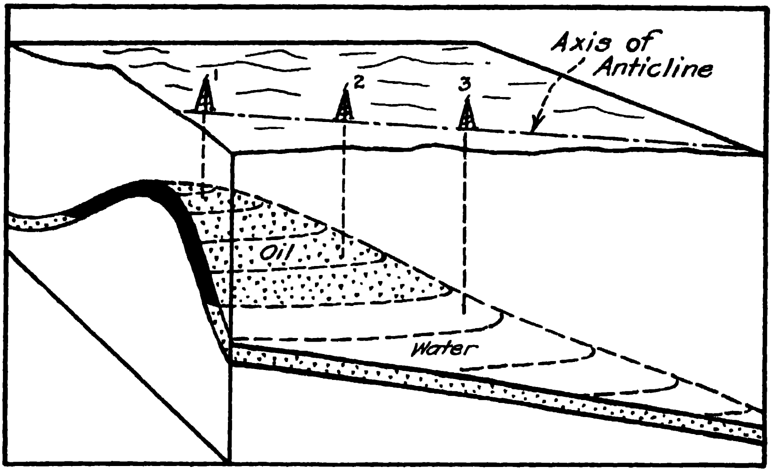


FIG. 4.—Illustrating oil accumulation on "terrace structure."

It must be remembered that the axes of anticlinal folds are seldom straight lines, but curve in both the horizontal and vertical planes (see Fig. 8). Where they curve sharply, strata on the inside of the fold are

compressed while those on the outside are put under tension, thus forcing the oil toward the outer flank, away from the point of greatest compression. Especially prolific concentrations of oil may be expected where a



(*After D. Hager*).

FIG. 5.—Stereogram of a plunging anticline.
Wells Nos. 1 and 2 are productive; No. 3 encounters edge water.

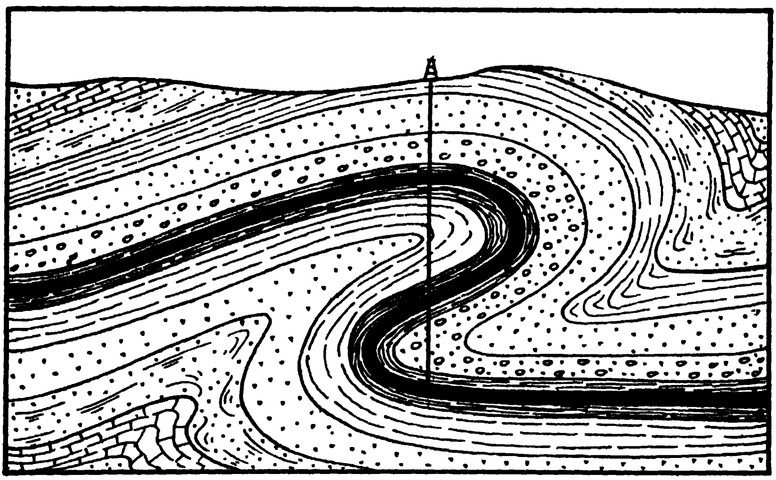


FIG. 6.—An overturned anticlinal fold, showing how one well may intersect the same oil sand three times.

change in strike of the axis occurs, and especially on the convex side of the fold.[11]

Many anticlinal folds that are productive of oil occur along the lower flanks of major uplifts. The greatest accumulations of oil in

such cases are generally found on the basinward flank of the anticline, this side having the advantage of a greater area over which concentration of the oil has been operative (see Fig. 3).[10] In some cases the three

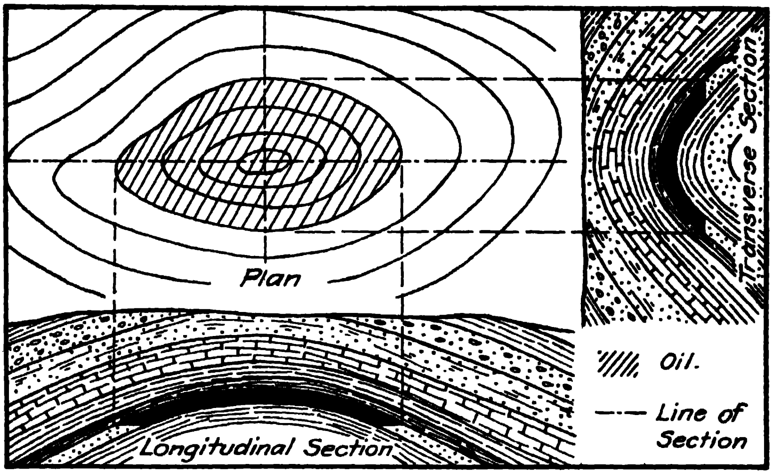


FIG. 7.—Dome structure illustrated in plan view by structure contours and by vertical sections through the major and minor axes.

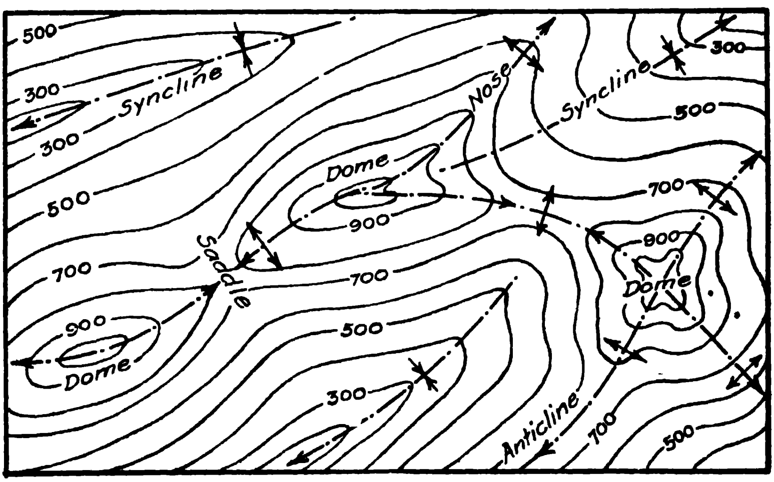
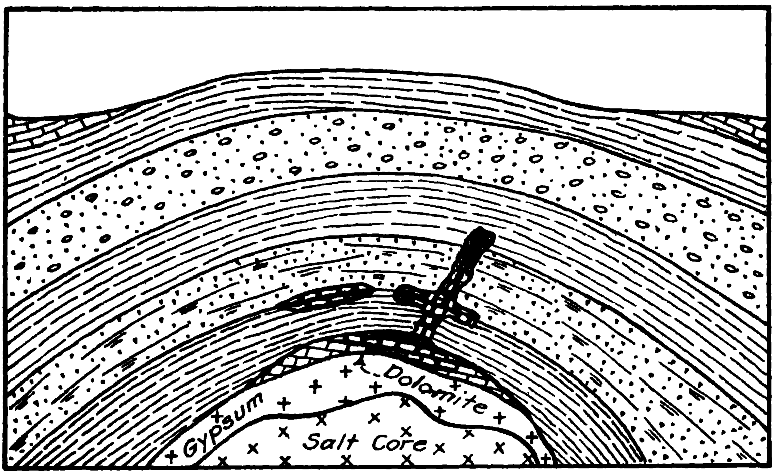


FIG. 8.—Structure contour map showing form of top surface of a producing oil sand and illustrating manner of indicating various structural features. Oil accumulates under the three domes.

anticlinal zones, occupied by gas, oil and water respectively, will be fairly well developed, with a well-defined "edge-water" line marking the limits of the oil pool. In other cases, particularly in low-dipping strata, the oil and gas will be intimately associated in all parts of the productive

zone, and the edges of the pool will produce mixtures of oil and water. The edge-water lines are often at different levels on opposite flanks of an anticline, and may move up- or down-dip at times, with changes in porosity of the containing stratum.

Domes.—In the case of domes (qua-quaversal structure), we have the conditions favoring high concentration of oil and gas best developed. The structure here dips off in all directions from a crestal point, and oil is concentrated from all flanks over the entire area of the dome toward its summit. Many of the most productive oil fields exhibit well-developed dome structure, and in nearly every case the highest concentrations of oil and gas are found at or near the structural crest.



(*After G D Harris, La Geol. Survey*).

FIG. 9.—A typical salt dome deposit.
Oil accumulates in porous limestones above and on the flanks of the salt core.

Domes are of various forms (see Fig. 7 and 8). They are the result of two or more intersecting anticlines or of local variations in dip on the flanks of some larger fold. More rarely they are formed by pressure from below of intrusive igneous rocks, or as a result of pressure developed by the crystallization of large bodies of salt (salt domes, see Fig. 9). Popular usage does not clearly distinguish between what are sometimes called "elongated domes" and ordinary anticlines. All anticlines are long, narrow domes in the sense that they are closed structures, plunging or flattening out at each end where they merge with other structures. Hager[11] suggests that only closed structures in which the length does not exceed three times the width, be spoken of as domes.

Locating Test Wells on Domes and Anticlines.—In locating test wells on dome and anticlinal structure, the prospector should aim to penetrate

the petroliferous stratum at its structural crest. Here nature's forces are concentrated—the gas pressure is greatest, and the possibilities of high and long-continued production are at their best. A well drilled in any other location, if unproductive, would still leave the presence or absence of oil in the formation in doubt. An unproductive well on the structural crest settles the issue at once unless there is reason for believing that the sands are lenticular, or are influenced by irregular cementation. The only exception to this general rule of locating the test well to intersect the supposed oil-bearing stratum at its structural crest, is in cases where abnormally large gas concentrations under high pressure are expected, due to unusually favorable structural conditions. In such cases, a well directly on the crest of the structure might produce only high-pressure gas for a considerable period before oil could force its way up from lower levels into the well. A well located slightly down-dip from the structural crest would in such a case produce oil at once, and could be operated under more favorable conditions.[11]

It is well to remember in selecting sites for test wells on asymmetric anticlines that the productive limits of the pool will probably extend farther from the axis in the direction of the flat-dipping flank than on the side of the steeply inclined flank (see Fig. 2). Consequently, if there is doubt concerning the precise location of the axis, preference should be given to the flat-dipping side in locating the initial well.

In determining the location of axes of asymmetric folds at depth from surface measurements, it should be noted that the axis of a stratum several thousand feet deep may be in quite a different position than are the axes of the surface strata, though they are parts of the same fold. This is demonstrated in Fig. 2, in which it may be observed that the axes of the deeper strata fall successively to the right of the over-lying strata. It is obvious that a careful structural study based on accurate field data is essential before a test well can be properly located to penetrate the oil stratum at its structural crest.

Monoclines.—When the crest of an anticlinal fold is eroded away, a partial cross-section of the strata making up the fold is exposed at the earth's surface and the undisturbed lower flanks form what are called "monoclines." (See Fig. 10.) If one or more of the outcropping strata contain oil, the nature of the material will be made evident by accumulations of oil and bituminous materials along the outcrop. The upward pressure of gas and the hydrostatic head, still operative in the oil-bearing strata, tend to force the oil out of the sands, accumulating it in pools on the earth's surface, from which it evaporates or is carried off by the natural water courses. Wastage of oil, as a result of erosion of anticlinal crests and exposure of oil-bearing strata, has undoubtedly been responsible for the dissipation of much of the petroleum accumulated by nature's processes in former geologic periods. Fortunately, if the deposit is a

large one, the oil is capable, by reason of its own physical properties, of sealing the outcrop and preventing escape of the oil originally stored in the lower flanks of the fold. This is accomplished by evaporation of the lighter and more volatile constituents of the oil, leaving in the surface rocks a residual product of solid paraffin or asphalt which completely closes the rock pores and prevents further migration from below. The remnants of oil deposits, so exposed and yet protected from further loss, are readily located by their prominent bituminous outcrops, are easily developed and serve as important sources of petroleum in many fields.

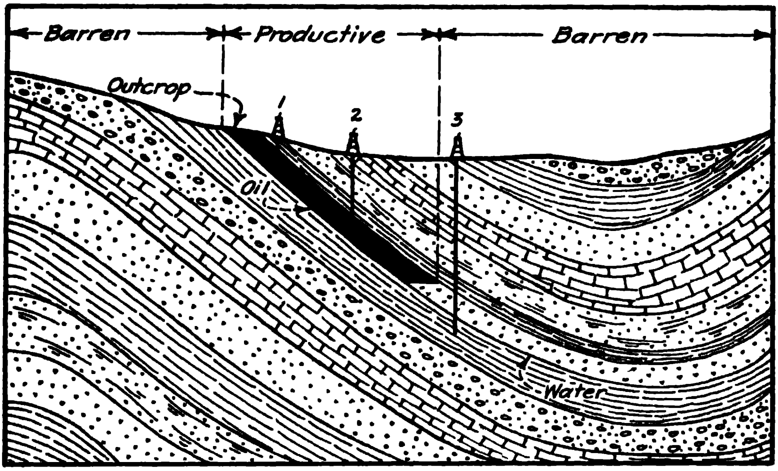


FIG. 10.—Illustrating simple monoclinal structure.

The shallow well, No. 1, produces heavier, more viscous oil than No 2, due to evaporation of the lighter constituents at the outcrop. Well No. 3 encounters edge water.

In locating test wells on monoclinal structure, the wells must be located sufficiently down-dip to penetrate the oil stratum below the zone of oxidation, which may extend for several hundred feet below the outcrop. Oils produced from the upper portion of the stratum, near the outcrop, are likely to be heavy and viscous, and the wells will be small producers because of the difficulty of inducing flow from the sands and because of the absence of gas. Except for this limitation, considerations influencing location of wells on monoclinal structure are identical with those discussed in connection with anticlines and domes. If the dip of the outcropping strata is measurable, it is a simple matter to calculate from the observed angle the proper distance of the well from the outcrop, to intersect the oil zone at any desired depth.

Faults.—Faulting, being the result of the same earth forces that bring about folding of strata, is often in evidence in oil-bearing formations, and must be considered as a factor in oil accumulation. A fault may

intersect an oil deposit and so displace one portion with respect to the other that for all practical purposes they become separate deposits (see Figs. 11, 12 and 13).[11] Faults sometimes fracture a porous monocli-

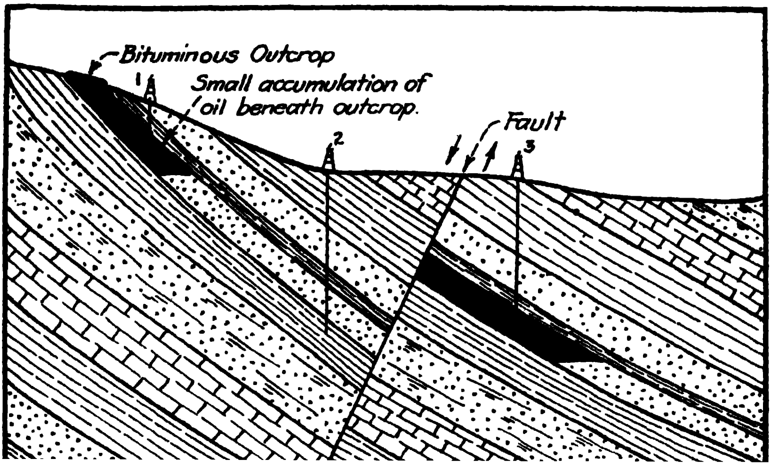


Fig. 11.—A faulted monocline.

The illustration shows how a fault may interpose an impervious stratum across the lower part of an oil-bearing stratum, permitting accumulation of a deposit of petroleum, which is sealed by the fault "gouge" and prevented from escaping up the dip of the structure. Wells Nos. 1 and 3 are productive. Well No. 2, halfway between, encounters edge water.

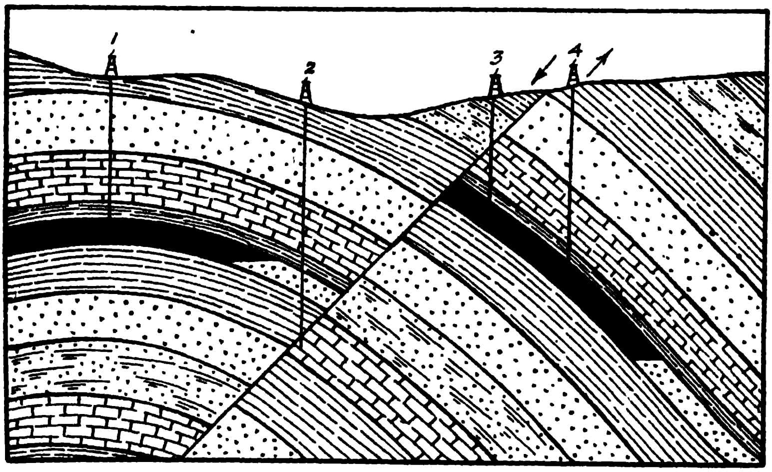


Fig. 12.—A faulted anticlinal arch.

The figure illustrates oil accumulation on both the up-throw and down-throw sides of a fault, and shows how faulting may leave barren places in anticlinal structure. Wells Nos. 1, 3 and 4 are productive; No. 2 encounters edge water; No. 3 intersects the fault plane.

nal stratum, formerly barren of oil, and interpose a stratum of impervious clay or shale across the faulted face in such a way that a structural trap is formed in which oil may subsequently be concentrated. It is

commonly supposed that faults provide channels of communication between strata originally separated from each other by impervious beds. Fluids may thus be transferred from stratum to stratum across fault planes, perhaps dissipating accumulations of petroleum through great thicknesses of formerly barren rock (see Fig. 13). While the influence of faults on oil accumulations must always be somewhat problematical, they constitute a disturbing structural feature, which the prospector must take into account in locating test wells.

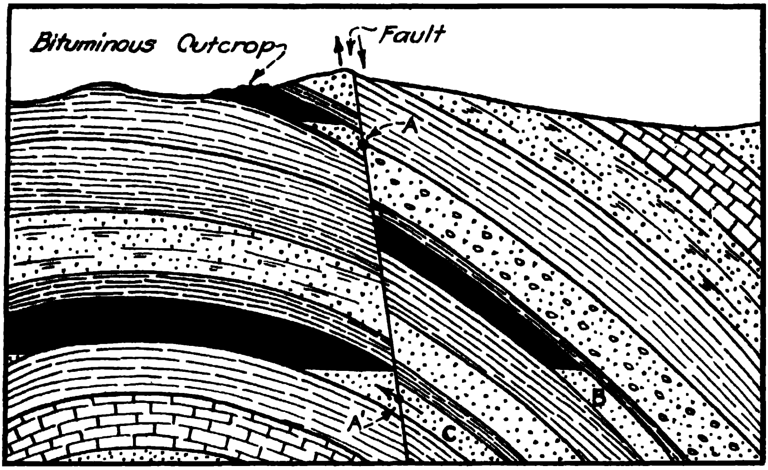


FIG. 13.—A faulted anticlinal arch.

The down-throw side has moved from A to A', dislocating two oil sands, B and C. The up-throw side of B has been eroded away, but a remnant of the up-throw side of C still remains below the bituminous outcrop. Oil from the down-throw side of C has migrated across the fault plane and accumulated in the crest of a porous sand, formerly barren.

Unconformities.—A period of erosion, perhaps accompanied by tilting and folding, may intervene between two periods of deposition, leaving the accumulations of the two periods unconformable at their surface of contact. Strata of the older series will thus dip at entirely different angles than do those of the younger series. Sealing of porous beds of the lower series, by impervious layers of clay or shale at the base of the upper series, may provide favorable conditions for the accumulation of petroleum in the older rocks, against the unconformity (see Fig. 14). In other cases, oil originating in the lower formation may flow along and across the unconformity, accumulating in upper strata only remotely related with those from which the oil emanates. Such conditions are exceedingly difficult to decipher in the field, and surface structural studies will be of little assistance in working out the true situation.

Lenticular Deposits.—Lateral variation in oil-bearing strata, particularly in sands and sandstones, is often responsible for marked changes in the oil content of strata at different points (see Fig. 15). This

is due to variation in character of grain structure, cross-bedding and other irregularities resulting from the manner of original deposition of the containing rock. The result is a succession of lenses of porous sands

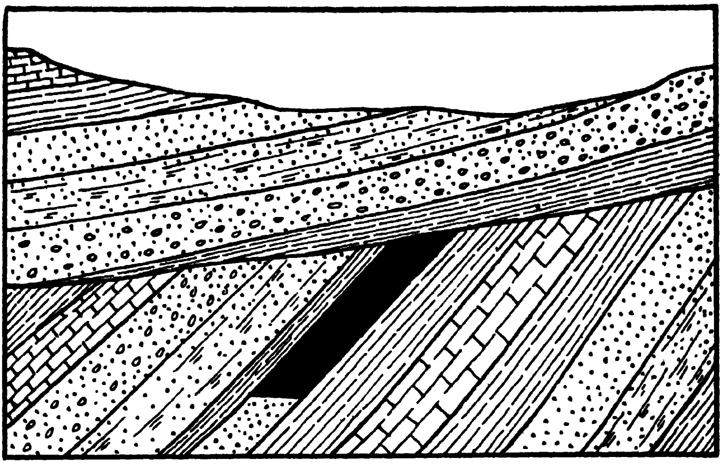


FIG. 14.—Illustrating accumulation of petroleum against an unconformity. The impervious stratum at the base of the upper series prevents escape of the oil.

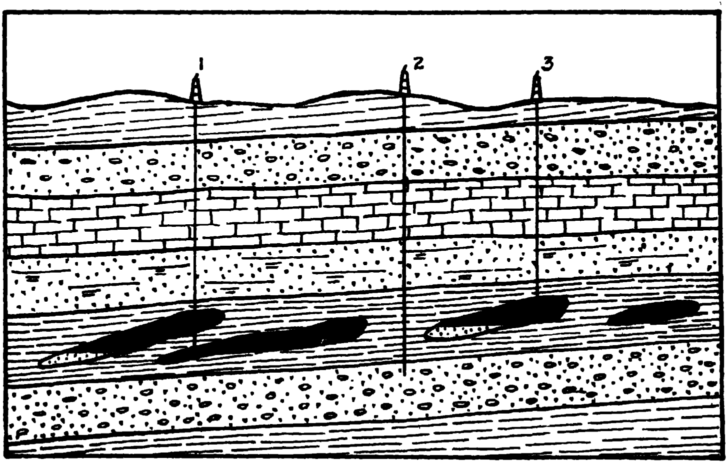
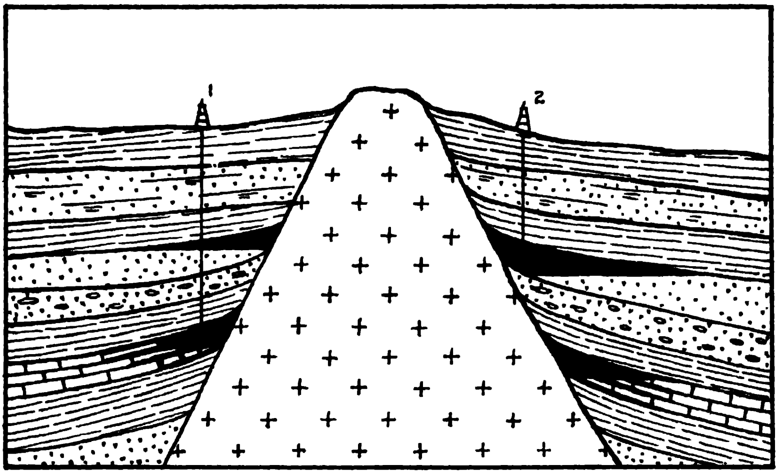


FIG. 15.—Lenticular deposits.
Lenses of coarse sand embedded in oil-bearing shales serve as local centers of concentration. Well No. 1 produces from two lenses, No. 3 from only one. Well No 2, between No. 1 and No. 3, is unproductive.

embedded in relatively close-grained rocks, the whole forming what is apparently one continuous, fairly well-defined stratum. Oil naturally seeks out the porous lenses in which to accumulate, leaving the less

porous rocks comparatively barren. In general, the major concentrations would be influenced by anticlinal structure in such a lenticular stratum, but surprising differences in saturation of the sands will be in evidence. Perhaps the crest of the structure, which would ordinarily be selected as the best site for a test well, will be almost barren, while an apparently less favorable position, with respect to the structural evidence, will be highly productive. Such conditions can scarcely be taken into account in geological surveys for the location of test wells, and constitute one of the inherent uncertainties with which the oil prospector must contend.



(*After F. G. Clapp*).

FIG. 16.—Illustrating occurrence of oil on the flanks of an intrusive volcanic neck. Oil accumulates in upturned edges of porous sedimentary rocks Well No. 1 may produce oil from two horizons, while No. 2, located nearer the intrusive contact, produces only from the upper horizon.

It has been stated that the original organic material from which petroleum is derived was probably deposited in sedimentary marine strata in shallow waters along the shores of bays and lagoons. Most sedimentary strata are laid down against shore lines, and any cross-bedding that might be developed, as well as any segregation of coarse and fine detritus during deposition, would be roughly parallel with the shore line against which it has been formed. It follows that the lenses or channels of relatively porous sands in which petroleum later accumulates should be approximately parallel to the shore lines of the period in which they were formed. Field evidence shows this to be generally true.[12] The location of ancient shore lines is therefore of assistance to the petroleum prospector in aiding him to predict the probable trend of lenses and channels that are responsible for unequal distribution of petroleum in the containing stratum.

Salt Dome Deposits.—In portions of the Gulf Coast field of the United States, petroleum is found in close association with deposits of salt (see Fig. 9). The salt deposits have been responsible during their accumulation for considerable upward pressure, resulting in doming of the overlying sedimentary rocks. This is probably a result of the expansive force of crystallization. Replacement of lime by magnesia in overlying limestone beds has brought about dolomitization, leaving the limestone fairly porous. Doming of the sedimentaries has effected concentration of petroleum contained in the surrounding rocks, which accumulates in the dolomitic limestone at the summit and along the flanks of the domes.

Petroleum Deposits in Association with Volcanic Intrusions.—In certain Mexican fields, petroleum is found in sedimentary strata, the edges of which have been folded up along the flanks of volcanic necks (see Fig. 16). Apparently, in such cases the intrusive igneous rocks have merely been responsible for the development of folds into which oil has migrated from the surrounding sedimentary formations. Such deposits are rare and do not constitute any exception to the universal derivation of petroleum from sedimentary rocks.

SURFACE INDICATIONS OF PETROLEUM

The attention of the prospector is often attracted by surface indications which have come to be regarded as indicative of the presence of petroleum. These include oil seepages, hydrocarbon gas emanations, bituminous outcrops and deposits of asphalt and paraffin waxes. In addition to these positive indications of petroleum, there are other occurrences which do not necessarily indicate the presence of petroleum, but which are often associated with oil deposits. Salt and brine, sulphur and sulphurous waters and gases, acid waters, oil shale and burnt shale, are commonly regarded as offering corroborative but not conclusive evidence.[10]

Oil Seepages.—Oil seepages offer the most direct evidence of the presence of petroleum. In places where oil-bearing rocks outcrop at the surface, or where the cap rocks overlying an oil deposit have been fractured, oil may come to the surface as "oil springs," or may accumulate in pools along the outcrop or fault plane. The flow of oil is seldom copious because of the tendency of petroleum to seal such outlets by the accumulation of solid hydrocarbons, resulting from evaporation of the lighter liquid constituents. Petroleum escaping in this way, even in minute quantities, will often make its presence known by the formation of iridescent films on water in ponds, wells, springs and streams. This film, which is quite characteristic, somewhat resembles that formed by oxide of iron, but the latter will be readily distinguished by its brittleness. The oil film is cohesive and persistent, and displays a peculiar tendency to

disperse on the water surface when brought into contact with a little ether vapor, or with a drop of ether on the end of a glass stirring rod.

Hydrocarbon Gases and Related Phenomena.—Because of their common association in nature, hydrocarbon gases are also significant indications of the presence of petroleum. Cap rocks may be sufficiently impervious to prevent oil seepages from reaching the surface, but the slightest crevice or joint plane will serve for the passage of gas. Hydrocarbon gases, being colorless, are not so conspicuous as oil seepages, but their presence is often made apparent when associated with oil, by their characteristic petroleum odor. They burn readily and are explosive when mixed with proper proportions of air.

The petroleum odor of hydrocarbon gases associated with oil deposits is often masked by the stronger odor of hydrogen sulphide and sulphur dioxide, with which they are commonly contaminated in nature. The characteristic odor of ammonia is occasionally observed in gases associated with petroleum. Rogers* has suggested that ammonia may be derived from naturally occurring ammonium compounds, such as ammonium sulphate, by contact with hydrocarbons in either the liquid or gaseous phase. Inter-reaction of the two sulphur gases with water sometimes results in the formation of native sulphur in the form of a sublimate about the openings through which the gases escape. Sulphuric acid similarly formed may give the ground waters of the locality a slight acid reaction. Rogers also suggests that sulphur and sulphur compounds are in many cases derived from sulphates by the reducing action of hydrocarbons. Pyrite, though often present in rocks associated with oil and gas, is not considered as an indication of petroleum. The presence of sulphur and sulphur gases cannot be regarded as more than corroborative evidence, since they are often formed by reactions which are not in any way related to the occurrence of petroleum. Even hydrocarbon gases are not infallible evidence, as "marsh gas," which is chiefly methane, is often found where oil is not. If the gases are "wet," *i.e.*, if they contain ethane, propane, butane or hexane as well as methane, the presence of liquid petroleum in association with the gas is more definitely assured.

When escaping through argillaceous rocks at the earth's surface, gases have a tendency to build up clay mounds about the openings through which they issue. These mounds, generally in the form of a cone, are called "mud volcanoes." They vary greatly in size from small "pimples" to hills covering several acres, and simulate on a small scale all the characteristics of true volcanic activity. On erosion, the crevices on which the mounds accumulate may become filled with mud, forming mud

* Rogers, G. S., "Chemical Relations of Oil Field Waters in the San Joaquin Valley, California," U. S. Geol. Survey, *Bull.* 653, 1917.

dikes. Mud volcanoes and mud dikes prominently mark the position of gas "seeps" in many oil fields.[8]

Bituminous Outcrops.—When liquid hydrocarbons are subjected to contact with air, evaporation of the lighter constituents leaves a solid residue of asphalt or paraffin wax. Oxidation of the heavier hydrocarbons is also a factor in this process of solidification. The sandstones in which these solid hydrocarbons are deposited become tough and resistant to weathering and disintegration, forming prominent bituminous outcrops where the oil-bearing strata intersect the surface. These bituminous deposits are quite characteristic, and in many fields have attracted the attention of prospectors to the particular strata with which they are associated. In some instances deposits of liquid petroleum are found in monoclinal structures a few hundred feet down the dip of the strata, below the outcrop. In other cases, bituminous sands are apparently merely remnants of former oil deposits which have been eroded away. In any case, however, they prove in no uncertain manner that the strata in which they occur are petroliferous; and they may serve to focus attention on their particular horizon in anticlinal structures in the vicinity, where sealed deposits of petroleum may be found.

If the bituminous material has been subjected to weathering and oxidation, only traces of the petroleum formerly present will be in evidence, occasionally so little that delicate tests must be made to determine its presence. Petroleum hydrocarbons are soluble in chloroform, ether or carbon bisulphide, the solvents being discolored to various shades of brown by the hydrocarbon dissolved. The depth of color depends upon the amount of soluble hydrocarbon present, but the test is very delicate and only a trace is necessary to bring about the distinct discoloration of the solvent. A little of the dried and powdered material heated to redness in the closed end of a glass tube will yield oil vapor which condenses near the open, cold end of the tube as a yellowish-white or brownish "fog," or in small drops. Black manganese oxide often stains a sand or sandstone so that it apparently contains a carbon-like residue, but it is readily distinguished when the solvent and heat tests are applied. Certain carbonate waters and other aqueous solutions containing in suspension finely divided and concentrated organic residues of vegetable origin, closely resemble petroleum in general appearance, but have none of its specific properties.

Mineral Waxes.—The mineral waxes, particularly Gilsonite, Grahamite, Albertite and Ozocerite, are derived directly from liquid petroleum by segregation of the lighter constituents. They are commonly found in veins or fissures and are often spoken of as "intrusive" petroleum. Such deposits are sometimes directly connected with deposits of liquid petroleum, and in any case serve as conclusive evidence of the petroliferous character of the rocks in which they are found. Outcrops of such veins,

or even fragments of mineral wax resulting from erosion of wax deposits, are therefore of interest to the prospector for petroleum.

Bituminous Shales.—Deposits of bituminous shale containing "kerogen" from which petroleum may be derived by natural processes, though offering no definite assurance that petroleum is present in association with them, are nevertheless indications that the prospector cannot afford to ignore.* When the raw material from which petroleum may be derived is known to be present in the region, a search for localities in which the conditions are favorable for the necessary metamorphosis and accumulation may result in the location of deposits of liquid petroleum.

Strata containing bituminous shales have in some cases become ignited —perhaps spontaneously—and all or most of the carbonaceous material has been consumed, leaving hard, resistant layers of "burnt shale." Such shales are usually highly colored by red oxide of iron, and because of their hardness and resistance to weathering, often form the crests of prominent ridges and "tables." Even though they are no longer carbonaceous, the knowledge that they were so at one time may be suggestive to the prospector in searching for localities which might have escaped the destructive agency, or for localities in which hydrocarbon vapors might have condensed, forming deposits of petroleum.

Saline Ground Waters.—Knowledge of the universal association of salt water with petroleum stimulates interest on the part of the prospector in all brine springs and deposits of salt. Such occurrences, however, are very common in nature, and are not necessarily indicative of the presence of petroleum. They are to be regarded at best as nothing more than corroborative evidence to substantiate predictions based on other and more positive indications.

"Paraffin Dirt."—In the vicinity of the salt domes of the Gulf Coast region, the surface soil contains quantities of a yellow, waxy substance resembling paraffin or beeswax, which has been given the name of "paraffin dirt." It is supposed by oil prospectors to be indicative of the presence of petroleum in the vicinity, but many question its supposed intimate relationship. A detailed study of several such occurrences has led to the opinion that it is derived from decomposing vegetable matter in the soil, and is not related to the petroleum deposits of the region.

Stunted Vegetation.—The effect of petroleum present in surface soil is detrimental to the growth of vegetation. Plant life in such soils is either entirely lacking or is stunted. So marked is this influence in regions where vegetation is ordinarily prolific, that in certain instances

* The "pyro-bitumens" do not, as a rule, respond to the solvent tests described above, and must be heated before their carbonaceous character becomes evident. A little of the powdered material, heated to redness in a glass tube closed at one end, will yield oil vapors which condense on the walls of the cold end of the tube. The odor of these vapors is quite characteristic.

attention has been directed to the soil, which on examination has been found to contain traces of petroleum. Since plant life may be absent for many other reasons than the presence of petroleum in the soil, such an occurrence is of only slight significance.

SUBTERRANEAN EVIDENCES OF PETROLEUM

It often happens that regions in which the presence of oil is suspected give little or no surface evidence on which to base predictions or estimates of oil content. If strata of suitable age—which, perhaps, are known to contain oil elsewhere in the region—are within reach of the drill, and if the geologic structure is favorable, the prospector may decide to drill a test well even though there is no tangible surface evidence. In such a case the conditions within the well must be closely watched for signs which might indicate the presence or absence of oil. Even when the surface signs are unmistakable, the evidence to be obtained from the log of the well during the drilling stage will be of great value in checking previous estimates, and in the subsequent development of the field through the drilling of additional wells.

Oil-saturated sand, or even traces of oil in the pulverized material bailed or pumped from the well, are of course direct evidence, and usually justify a pumping test of the stratum from which they come. Such a test is often necessary to determine whether or not oil can be produced in sufficient quantity to repay the cost of operation. The driller will always be on the alert for "shows" of oil when the drill enters a soft, porous sandstone after penetrating a hard layer of close-grained "shell." It will often happen that the finely pulverized material pumped or bailed from the well will be so thoroughly washed that its petroliferous character is not evident until tests are made. An ether or chloroform test will usually disclose the presence of oil.

Flows of hydrocarbon gases from a drilling well are always favorable evidence, especially if they contain gasoline vapors, or if they have a petroleum odor. Many sedimentary formations produce marsh gas (methane) which, if "dry" (*i.e.*, without hydrocarbons of higher molecular weight), is often formed in the absence of petroleum, and therefore it is not necessarily indicative of the presence of petroleum.

Traces of solid or semi-solid hydrocarbons, such as mineral wax, asphalt, fossil resin, tar or even coal or lignite, in the returns from a well, constitute favorable indications of the presence of oil.

Waters and gases containing hydrogen sulphide or sulphur dioxide are generally favorable indications unless the water is hot. Hot sulphur waters are characteristic of regions under the influence of volcanic and solfataric activity, conditions generally unfavorable for the accumulation of petroleum.

Brine is generally looked upon as an unfavorable indication when encountered in a prospect well. Though it is nearly always associated with petroleum, it generally underlies the oil; consequently, if a well produces brine, it is often inferred that the zone in which oil might be found has been penetrated and found barren.

In some fields it is found that the percentage of certain dissolved salts in the ground waters increases or decreases in a characteristic manner. In such cases it is possible to form some estimate of the proximity of an oil sand from a chemical analysis of the waters contained within the various strata penetrated by the well. Waters a short distance above the oil horizon in many fields are "sulphur waters," containing considerable percentages of hydrogen sulphide; but the shallow surface waters and those within the oil measures generally contain no sulphides. Carbonates, which are present only in moderate amounts in the shallow waters, increase in percentage as the oil zone is approached. If no chlorides are present, the carbonates may constitute the only dissolved salts in the waters immediately associated with the oil. As pointed out in the preceding paragraph, however, the waters underlying petroleum, occupying the lower horizons of the same strata in which the oil occurs (*i.e.*, "edge waters"), are often rich in chlorides. Although the surface and shallow ground waters contain considerable percentages of dissolved sulphates these are found to diminish as the oil measures are approached, and finally entirely disappear. Outside of localities in which petroleum occurs, on the other hand, sulphates are found in even the deepest waters.

It has been observed in many oil fields that the ground temperatures are appreciably higher than in regions where petroleum is not present. The normal temperature gradient indicates a rise in temperature of approximately 1°F. for each 60 or 70 ft. of depth; but in certain oil fields where careful temperature measurements have been made, it appears that there is a rise in temperature of 1°F. for every 40 or 50 ft. The present data are too uncertain in character to warrant any definite correlation between ground temperatures and proximity to oil-bearing strata, but the information so far collected would appear to substantiate the general statement that ground temperatures higher than normal prevail in petroliferous formations. The prospector would therefore be justified in regarding unusual ground temperatures in a prospect well as corroborative evidence of the presence of petroleum; particularly if there were other evidences of more positive character. In this connection, however, the fact should not be lost sight of that high ground temperatures are also characteristic of regions where vulcanism is active, and that without more direct evidence of the presence of petroleum, ground temperatures are of little significance.

Aside from the more direct indications of petroleum suggested above, it should be pointed out that mere alternations of stratified porous and

impervious beds in horizons known to be petroliferous, are in themselves favorable indications.[11] Great thicknesses of either coarse or close-grained rocks, without variety in porosity and texture, never offer favorable conditions for the accumulation of petroleum.

GEOLOGIC AGE OF PETROLEUM-BEARING ROCKS

Palaeontological classification of petroleum occurrences the world over indicates that petroleum is not confined to any definite geologic period, but occurs in rocks ranging in age from the Cambrian to the Recent[12] (see Table VII). While petroleum is thus distributed through

TABLE VII.—GEOLOGIC AGE OF PETROLEUM DEPOSITS

Era	System	Order of productivity in the U. S.	Type of oil
Quarternary	Recent Pleistocene		Generally unproductive.
Tertiary or Cenozoic	Pliocene Miocene Oligocene Eocene	1	Generally asphaltic base petroleums. Tertiary formations produce more than half of the world's petroleum.
Mesozoic	Cretaceous	3	
	Jurassic Triassic		Generally unproductive.
Palaeozoic	Permian		
	Carboniferous Devonian Silurian Ordovician Cambrian	2 4 6 5 7	Generally paraffin base petroleums.
Proterozoic	Keweenawan Amikean Huronian		Unproductive.
Archeozoic	Archean		

a considerable portion of the geologic column, it is found that the more prolific horizons may be located within closer limits. More than half of the world's petroleum has been produced from rocks of Tertiary age.[10] Paleozoic rocks have also been particularly prolific. A broad classification serves to indicate that the bulk of our asphaltic oil comes from rocks younger than the Jurassic.[18] Much of the so-called paraffin base oil is derived from rocks older than the Permian. Lower Cretaceous, Jurassic, Triassic and Middle and Upper Permian rocks of North America are, as yet, unproductive.

Palaeontology finds one of its chief uses in the field of applied science, in petroleum exploration. Rocks may thus be identified by their fossil content as belonging to one or another of the geologic periods, and a knowledge of the petroliferous horizons of a particular region will aid the prospector in determining whether or not oil may be present in the formations within reach of the drill.[21]

A knowledge of the palaeontological and generic relationships* of petroleum greatly aids the prospector in roughly classifying areas which are improbable, possible or favorable for the production of petroleum. Unfavorable areas for the production of petroleum include, generally speaking, the more extensive areas of igneous rocks, all pre-Cambrian strata, intensely folded mountainous areas older than the Cretaceous, regionally metamorphosed strata, continental or fresh-water deposits, thick, uniform marine formations devoid of interbedded dark shales, limestones, marls and fossiliferous sandstones. Possible petroliferous areas include gently folded Cambrian and Ordovician strata, saline lake deposits, and highly folded marine strata younger than the Jurassic, especially those of Cenozoic age.[19] The prospector should give special attention to all marine and brackish water sediments younger than the Ordovician, especially if they are not intensely folded or faulted. Conditions are particularly favorable if the formation is made up of porous, thin-bedded sandstones, limestones and dolomites interbedded with shale; and if it appears that the sediments have been deposited in salt water at comparatively shallow depths.

THE PETROLEUM PROSPECTOR, HIS EQUIPMENT AND METHODS

Equipped with a knowledge of the characteristics of petroleum, with its manner of formation and accumulation, its associations and occurrence in nature, it is the task of the prospector to apply this knowledge in the field in the location of new deposits. The nature of the work requires a happy combination of technical and practical ability, a power to reason and deduce facts which must often be based on very slender and uncertain evidence. Geology is not an exact science. Good judgment and practical experience in field methods are of far greater value than mere academic understanding. Usually it will not be possible for the geologist to predict with certainty that petroleum will be found in commercial quantities in a given location. Perhaps the best information we can expect from him will be a statement that conditions are either favorable or unfavorable; and if favorable, the best position within the prospective area for the location of a test well should be selected by him. The possibility that a well thus located by scientific methods may prove

* WHITE, D., Genetic problems affecting search for new oil regions, *Trans.*, Am. Inst. Mining & Met. Engrs., vol. 65, pp. 176–198, 1920.

unproductive is one of the inherent risks in petroleum exploration that must be recognized by all parties concerned in the enterprise.

There are many individuals who are led to place their faith in various devices for locating petroleum deposits without the aid of geologic skill. The divining rod in its various forms, oscillating plumb bobs and delicate electrical contrivances are urged by their devotees and inventors as infallible indicators of the presence of oil. While these individuals are often sincere in their belief, it may be stated that there is nothing in our present knowledge of natural forces that would justify any reliance in such devices. Magnetic disturbances in the vicinity of certain oil pools have been noted, but they are by no means commonly associated with oil deposits, and their occurrence is of doubtful significance. At any rate, their influence on the magnetic needle and on measurable electric ground currents is too uncertain to offer a means of locating favorable positions for test wells.

A perusal of the foregoing pages will convince the reader that the determination of geologic structure should form, in large part, the basis for prediction. No matter how promising the surface indications, even though it is certain that petroleum is present, there can be no accumulation of commercial proportions unless the geologic structure is favorable. With a knowledge of the importance of structure, the careful prospector therefore gives much time and effort to the securing of all possible data that will aid in interpreting the structural conditions. Dip and strike of outcropping strata are carefully measured. Areal maps are prepared indicating the position of contacts, outcrops, fault planes and all data possible to secure by a detailed geological survey.[20] In many cases, lines of levels must be run and a contour map of the area constructed. Palaeontological studies are made to determine the geologic age of the section under observation. The work of the prospector may lead him far afield. Often outcrops many miles distant will furnish evidence of the nature of the horizons to be tested. From such complete and accurate data, it is possible to prepare vertical sections which will disclose the structural relationships, to select the most favorable location for a test well and to predict approximately the depth to which the well must be drilled to reach the petroliferous horizon.[21] Geologic mapping will be further discussed in Chap. III.

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Physical Properties and Chemical Constitution

1. Bacon and Hamor: "American Petroleum Industry," McGraw-Hill Book Co., N. Y., 1916. See particularly vol. 1, pp. 91–196.
2. Clarke, F. W.: The data of geochemistry, U. S. Geological Survey, *Bull.* 616, pp. 713–737, 1916.
3. Day, D. T.: "Handbook of the Petroleum Industry," John Wiley & Sons, N. Y., vol. 1, pp. 457–586, 1922.

minerals on government-owned land should reside in the national government, and that the privilege of producing oil might only be secured for a definite period of time under a lease and royalty system.

The Placer Law of 1872

The Placer Law of 1872, under which most of our present oil-producing properties were acquired, if on the public domain, provided that any citizen or alien who had declared his intention of becoming a citizen of the United States could preëmpt a tract of 20 acres or less in conformity with the general land subdivisions; and associations of eight or more individuals could make a joint location of 160 acres.[5] The exclusive privilege of searching for and producing oil from the area so claimed was secured by merely staking it, posting a notice on the ground and filing a claim for it at the nearest public land office. Thereafter the claimant retained his exclusive rights as long as he expended at least $100 in developing the property during each calendar year. If he failed to perform the annual "assessment work," the land became subject to relocation by any other claimant. After $500 had been expended in developing the "claim," the law provided that the locator could secure a patent conveying absolute title, without the obligation of performing further assessment work, on payment of a certain nominal sum per acre, and having the land surveyed by a licensed mineral land surveyor. Certain provisions of the Placer Law were found to be inappropriate when applied to oil and gas land, and in 1909 large areas of prospective oil land on the public domain were withdrawn from entry pending the passage of a leasing law, which, however, was not passed by Congress until 1920. Placer claims located under the law of 1872 are still valid, as long as the provisions of the old law are adhered to.

The Mineral Land Leasing Law of 1920

The Mineral Land Leasing Law of 1920 applies to petroleum, natural gas, oil shale, coal, phosphate and saline deposits still remaining on the public domain. Under its provisions,[4] lands containing these mineral products are permanently withdrawn from location and patent under the earlier mineral land laws, and can only be exploited on a leasing basis, involving payment to the government of a bonus, an annual rental and a royalty, or percentage of the mineral produced. The exclusive right to prospect for these minerals on the public domain is granted for particular areas having specified boundaries, through the granting of a prospecting permit by the Secretary of the Interior or his representative.

Prospecting permits may be granted to any citizen of the United States or to any corporation, a majority of the capital stock of which is held by

citizens of the United States. The permit grants to the applicant the exclusive privilege of prospecting for oil and gas within an area of 2,560 acres (4 sq. mi.) or less, for a period of 2 yr. However, a prospecting permit cannot be issued to grant such privileges within the geologic structure of any producing oil field. The area covered by the prospecting permit must be rectangular, reasonably compact in form and not more than 2½ times as long as it is wide; and it must conform with the public land subdivisions if the land has been surveyed. Non-contiguous tracts within a limited radius may be included in a permit when conditions are such that, because of previous grants under other laws, a reasonable area of contiguous land cannot be procured. The area comprised within a permit may not include land within any national park, forest reserve, Indian reservation or in military or naval reservations. The applicant may not hold more than one permit on the same geologic structure, nor more than three subsisting permits within the same state. He must furnish three references certifying to his good reputation and business standing, as well as a bond of $1,000 conditioned against his failure to repair promptly any damage that may be done through improper methods of drilling and operation.

The holder of a prospecting permit must mark all corners of the area covered by the permit, and must commence actual drilling operations with a "substantial and adequate drilling outfit" within 6 mo. Within one year he must drill one or more wells to a depth of at least 500 ft., and within 2 yr. he must drill at least one well to a depth of 2,000 ft. or more, unless valuable deposits of oil or gas are found at shallower depths. Other individuals holding surface rights to the area covered by a permit must be reimbursed by the prospector for any damage to crops, buildings or other property. Twenty per cent of the gross value of all oil or gas produced must be paid to the government until such time as a lease to the land is granted.

The life of a prospecting permit may be extended over a second 2-yr. period if in the opinion of the Secretary of the Interior additional time is necessary to test the land. Some modifications are introduced into the time limits specified in the issuance of prospecting permits for lands in Alaska, because of the difficulty of conducting drilling operations in that region. If oil or gas is not discovered on the area covered by the permit within the specified time, the permit terminates and the land automatically reverts to the government. The government reserves the privilege of granting prospecting permits or leases for other minerals than oil or gas on the same area, together with right of entry for other parties holding such permits or leases.

Reward for Discovery.—Upon establishing to the satisfaction of the Secretary of the Interior that valuable oil or gas deposits have been discovered within the limits of the land embraced in a prospecting permit,

the owner of the permit is entitled to a lease of one-quarter of the land included within the permit, or for at least 160 acres if there be that area included, on a royalty of 5 per cent of the gross value of the oil and gas produced. The discoverer of oil and gas is entitled to a preferential right to lease the remainder of the land included within his permit, at such royalty as may be fixed by the Secretary of the Interior, and under such conditions as may be required of other lessees in the same locality.

Leasing of Government-owned Oil and Gas Lands on Geologic Structures Known to Be Productive.—All public lands known to be productive of oil and gas before the passage of the leasing law of 1920, and all areas not covered by prospecting permits which have been proved productive since 1920, may be leased from time to time by the government, at a stated royalty, not less than 12½ per cent, to be determined in each case, or an annual rental of $1 per acre for so long a time as the land may remain unproductive. The land is divided into tracts of 640 acres or less—areas not more than 2½ times as long as they are wide—and the tracts are offered for lease at auction to competitive bidders. The lease is awarded to the individual or company offering the largest bonus, the bonus so offered representing the amount that the bidder is willing to pay for the lease in addition to the set royalty or annual rental.

The successful bidder must furnish a certified check for one-fifth of the amount of his bid on the date of sale; and he must also file a statement certifying that he is a citizen of the United States, or in the case of a company the articles of incorporation must be filed together with a statement indicating the residence and citizenship of its stockholders. The bidder may not hold another lease on the same geologic structure, nor more than two other leases, or a lease and a prospecting permit, within the same state. On being awarded the lease, the successful bidder must pay the remaining four-fifths of his bonus within 30 days, together with the first year's rental of $1 per acre. He must also file a bond of $5,000 to be forfeited to the government in case of failure to comply with any of the terms of the lease.

The lease conveys exclusive rights to drill for, remove and dispose of oil and gas from the land for a period of 20 yr., with a preferential right to renewal for successive 10-yr. periods at such terms as may be agreed upon by both parties. The government recognizes no obligation to renew the lease unless the lessee is willing to meet the terms offered by competitive bidders. The lessee must proceed to drill the land within 3 mo. from the date on which the lease is granted, continuing development until there is at least one well on each 40-acre tract. The annual rental is credited against the royalty payments—that is, rental is actually paid on a producing lease only when the royalty payments amount to less than $1 per acre per year. It is provided that the government may

reduce the royalty payments when the production of a well falls below 10 bbl. per day, if it appears to the interest of the government to do so.

The lessees must provide the government with copies of all sales contracts, monthly statements of production, well logs and other essential data in evidence of proper payment of royalties, and as proof that the work is being properly conducted. Government agents have access to the property and the records at all times. Many other details covering such matters as payment of taxes, wages, prevention of waste, assignment of leases, easements or rights-of-way, action in case of abandonment of property or default in terms, etc., are discussed in the "Regulations" of the General Land Office.[4] Administration of the law once the leases have been granted has been placed under the control of a division of the U. S. Bureau of Mines. Classification of lands prior to leasing is performed by the U. S. Geological Survey.

"Relief" Measures under the Mineral Land Leasing Law of 1920.—Withdrawal of all unpatented oil and gas lands in 1909, and the delay of 11 yr. before the passage of the leasing law, left locators under the earlier Placer Law who had not obtained patents to their claims in a most unsatisfactory position. They were apparently without semblance of title to the withdrawn land, and yet they were obligated to continue in possession and to continue performance of assessment work if they would secure any concessions that might be allotted to them under the proposed leasing law. In many cases wells were sunk and oil produced and sold after the land had been withdrawn, on the expectation that claims located under the earlier law would be validated. The government instituted suits to recover all such lands on which oil had not actually been discovered prior to the date of withdrawal. These suits were contested and carried through the courts for many years, during which time the profits derived from the product of the land were accumulated in escrow pending a final settlement.

The Mineral Land Leasing Law of 1920 provides that if a claim to prospective oil and gas land had been initiated under the Placer Law prior to July 3, 1910, on withdrawn lands, and if claimed and possessed continuously from that time, and if the claimant had drilled a productive well on the land before the passage of the leasing law, he is entitled to a 20-yr. lease on condition that he pay a royalty of one-eighth of the value of all oil and gas produced, both prior to the issuance of the lease (since 1910) and subsequent thereto.

At the time of the withdrawal of mineral lands in 1909, certain areas were designated as naval reserves, the intention being to reserve the oil under them for the future needs of the United States Navy. Under the leasing law, claimants to placer locations were given a lease to such wells as were already productive, at a royalty of not less than 12½ per cent, to be fixed by the Secretary of the Interior. New wells on the naval

reserves may only be drilled by the lessee with the consent of the President of the United States or his representative; but in the event of further drilling being authorized, the original claimant to the land shall be given preference.

The relief measures under the leasing law also provided that locators under the Placer Law who had located claims on other than withdrawn lands, prior to October 1, 1919 (November 3, 1910, in Alaska), but had not made actual discovery of oil or gas prior to February 25, 1920, when the leasing law was passed, would be given a prospecting permit for the land if they had expended $250 in development work, and were not claiming portions of any naval reserve.

State-owned Oil and Gas Lands

Under various congressional grants and by constitutional provision, certain public lands have at times been allotted to the several states under conditions that permit of future conveyance by such terms as the individual states may prescribe.[3] In some states, for example, land has been allotted with the intention that the money derived from the sale thereof shall be devoted to educational activities. Some of this land has later been found to contain oil or gas, and has been the source of considerable income to the states concerned. In some cases river and lake beds belonging to the states have been developed for oil production. The conditions under which such land may be purchased or leased by individuals varies in the different states according to legislative enactment. Though some state lands have been sold outright, they are customarily leased under a royalty system, often with competitive bonus and rental features similar to those of the national leasing law. Such laws have been enacted by Oklahoma, Texas, Louisiana, Ohio, Wyoming, Montana, Nebraska, South Dakota, Colorado and Utah.

Oil and Gas Rights on Indian Reservations

Certain lands set aside as Indian Reservations in Oklahoma include extensive oil deposits of great value. Though such lands were originally inalienable or non-transferable, various subdivisions from allotments of the tribal estates to individual members have been authorized from time to time and some of the earlier restrictions against sale of the land have been removed, particularly in the case of Indians of partly white heritage. Leases may also be obtained from full-blooded Indian owners with the approval of the Secretary of the Interior and the Office of Indian Affairs.[1] Congress has passed special legislation covering lands owned by the Osage Indians, allotting surface rights to individual members of the tribe, but reserving mineral rights to the tribe as a whole. Leases may

be authorized by the tribal council and are sold from time to time at auction to competitive bidders through the Department of the Interior. A royalty of 20 per cent is exacted for wells producing 100 bbl. of oil per day or more, and 16⅔ per cent for wells of less than 100 bbl. The lease agreements provide that a well must be drilled on the property to the Mississippi line, a formation underlying the oil horizon, unless commercial production is obtained at shallower depths.

The Legal Aspects of Oil and Gas Land Ownership in the United States

Though classed as minerals, and therefore subject to the provisions of the United States Mineral Land Laws, it is recognized by the courts that petroleum and natural gas have peculiar attributes which distinguish them from solid minerals.[2] Both petroleum and gas, as long as they remain in the ground, are a part of the realty; that is, they belong to the owner of the land and are a part of it, as long as they are subject to his control. When they migrate to neighboring properties and come under another's control, the title of the former owner is gone. The owner of the land has no specific title to the oil and gas within his land unless he takes actual physical possession of them; that is, until they are brought to the surface and reduced to actual possession. Thereafter, they become the personal property of the owner of the well through which they are produced.

The ownership of the surface of the land may be separated from that of the different strata beneath it, and there may be as many different owners as there are strata. Hence, surface rights may be separated from mineral rights in the sale of land; but unless specifically reserved, oil and gas rights pass with the transfer of title to the land surface. A person who has title to subsurface minerals, but who lacks surface ownership, has the right to build a road over the land when necessary to haul machinery to the place selected for the well, and to such other use of the surface as may be strictly necessary for drilling and producing purposes. The right to drill wells to produce oil and gas from lower strata through a deposit belonging to another, as in drilling an oil well through a coal seam, exists at all times, although it must be exercised in such a way as to do no damage to the property of others.

Many complex questions arise in considering the rights of neighboring landowners producing oil and gas from the same reservoir. The courts have generally recognized the principle stated above, that the oil and gas does not belong to the landowner until reduced to actual possession at the surface; but the right to drill wells and produce oil or gas from one's own land is absolute and cannot be enjoined, supervised or controlled by a court or by an adjoining landowner unless unnecessary negligence result-

ing in damage to the common source can be shown. Under this interpretation, a landowner who drills a well into an oil deposit and allows the gas to escape and to waste cannot be restrained by injunction unless unnecessary negligence is evident. However, in some states statutes have been passed designed to prevent waste of gas or damage by infiltrating water, and these statutes have been declared valid. The principle upon which such legislation has been upheld is that no one has a right to waste natural resources to the injury of the public, or to wantonly destroy or injure a common reservoir in which others have an equal right. Although the owner of a well, according to one authority, may explode nitroglycerin or apply gas pumps or other artificial devices to increase the productivity of his wells, at another's expense, there are also decisions to the effect that a court of equity may, under common law principles, enjoin a landowner from using such devices.

OIL AND GAS RIGHTS IN FOREIGN COUNTRIES

Abroad, oil and gas rights are almost universally regarded as property of the state,[5] and ownership of minerals is usually separate and distinct from ownership of the surface. Particularly is this true of the Latin-American countries which trace their conceptions of law back to the early Roman law, in which ownership of all beneath the surface of the earth belonged to the Empire, agricultural settlers on the land being given only surface rights. Throughout Latin America, the principle that no one may obtain fee simple title to mineral land is fundamental. Possessory right subject to continued payment of an annual tax is the only form of title given.

In Mexico where the Latin system has attained its highest development, prospecting for minerals is free to all citizens, both on the public domain and on property owned by private individuals.[3] Upon discovery of mineral, a notice must be posted on the premises and a copy filed with a local government official. The claimant is then given the exclusive privilege of conducting exploration work for 3 months, and if he so desires he may then locate his claim or claims. After the claim is staked, the location notice must be published in the nearest local newspaper and the ground surveyed by a government engineer. After a period during which adverse claims may be brought forward, the claimant is given absolute title which is maintained as long as he continues to pay taxes, rentals and royalty. The unit mining claim, called a "denouncement," is 1 hectare, or a horizontal, square area measuring 100 m. on each side and containing 2.471 acres. Four hectares constitute a petroleum denouncement, and any number of such units may be located by one individual, either in groups or separately. If the surface of the property is owned by another, it is necessary to secure his consent before development work is begun,

usually by a money payment; but it is provided that if an equitable adjustment cannot be effected by direct negotiations with the owner, the land may be condemned by court proceedings. In addition to taxes, an annual rental of 5 pesos per hectare must be paid to the government, and a 5 per cent royalty on gross production of oil and gas. Three years are allowed in which to begin development after the claim is staked.

Prior to 1917, the earlier mining laws of Mexico did not nationalize petroleum and natural gas, the owner of the surface being conceded ownership to all hydrocarbons; but this was altered during the Carranza régime, and present laws consider all minerals, as well as hydrocarbons, the property of the government. The new laws however, are not intended to be retroactive; that is, leasing agreements made with landowners under the old laws are still valid, though considerable confusion has arisen through the efforts of the Mexican government to collect royalty taxes on land held under lease from private owners and in some cases conflicting claims have been allowed for the same land. The situation is further complicated by the recent temporary establishment of 20-m. "federal zones" along the seacoasts and zones 10 m. in width along the shores of inland lakes, lagoons and water courses, in which concessions for development and production of petroleum were for a time granted on a rental and leasing basis in direct conflict with previously established property rights in the same areas.

Canadian laws governing oil and gas rights vary somewhat in the different provinces of the Dominion.[3] The Dominion government has jurisdiction only over unappropriated "crown" lands in Manitoba, Saskatchewan, Alberta, the Northwest Territories, the Yukon Territory and within certain areas in British Columbia. Separate laws have been established governing the disposition of lands belonging to the provincial governments of British Columbia, New Brunswick, Ontario and Quebec.

The Dominion Laws of 1904 provide that prospecting shall be free, a prospecting permit giving exclusive privileges on an area of 1,920 acres for a limited time; and if oil is produced in paying quantities, the prospector may secure a patent to 640 acres on payment of $1 per acre, and the remaining 1,280 acres at $3 per acre. The law of 1914 makes provision for leasing crown lands for 21-yr. periods on payment of an annual rental of 50 cts. per acre during the first year, and $1 thereafter. It is provided, however, that rentals for the second and third years may be reduced by the amount expended by the prospector in conducting drilling operations, exclusive of casing and machinery.

The maximum area for a petroleum and natural gas location is 1,920 acres, and no person is permitted to acquire a greater area except by assignment. The lessee must commence drilling within 15 mo. of the date of his lease, and continue development with "reasonable diligence," the expenditure of $2,000 or more per year on each lease being considered as

fulfilling the obligations of the lessee under this provision. Leases are to be free of all royalty payments until January, 1930. Exploitation of Dominion oil and gas lands is only open to citizens of Canada, or to registered or licensed companies having their principal places of business in Canada. Further legislation in 1920 extended the above provisions to include all Dominion forest reserves.

Revised regulations governing prospecting for oil and leasing of lands in the Northwest Territories were announced following the discovery of oil at Fort Norman in 1920. Prospecting permits cover a maximum area of 2,560 acres and extend over 4 years' time. Annual rentals are as stated above, and the prospector is obligated to begin drilling within 2 yr. and to drill a 2,000-ft. well before the end of the fourth year unless commercial production is secured at a shallower depth. On discovery of oil, the operator is entitled to a 21-yr. lease on one-quarter of the area of his prospecting permit, for which he must pay an annual rental of $1 per acre and a royalty of 5 per cent until April, 1926, and 10 per cent thereafter.

Regulations governing prospecting and leasing on provincial lands are very similar to those outlined above, except that the payments exacted for prospecting permits, rentals and royalties differ somewhat in each case. Such royalties as are assessed are generally low, most of the burden on the operator being in the form of annual rentals.

ACQUISITION OF OIL AND GAS LAND FROM PRIVATE OWNERS

Oil and gas land may be acquired from private owners either by purchase in fee, or by leasing. The latter is the more common method because it is less costly, though the former gives greater security and freedom from restrictions.

Purchase in Fee

Actual purchase of the land is seldom economical if one is interested only in securing oil and gas rights, and a method involving purchase of mineral rights or oil and gas rights exclusively will usually give the purchaser ownership of that which he seeks, without obligating him to pay for surface rights in which he is not interested. The risk involved in purchasing land or mineral rights may be somewhat reduced by arranging that payment shall be made in instalments over such a period of time as will permit of a test to be made of the land before full payment is made.

Leasing

A lease may take a variety of different forms, ranging from a simple agreement conveying the right to produce and sell oil from the property for a stated period of time and for a stated consideration, to more compli-

cated contracts called "working bonds," which grant a lease involving term payments, or rentals, with option of purchase before a specified date for an agreed sum. The ordinary form of oil and gas lease provides for transfer of title to all oil and gas obtainable from the land during a stated period of years, or during a period limited by certain contingencies. The consideration is usually a percentage of the gross value of the oil and gas produced—often one-eighth—though, in many cases, it will also be provided that the lessee shall pay in addition an initial payment called a "bonus," and perhaps also an annual rental. The instrument by which such rights are conveyed must be drawn up in legal form, care being taken to state all of the conditions under which the lease is granted and the rights of the two parties to the agreement. On pages 50 and 51 will be found a typical form* for an oil and gas lease.

Terms of the Lease. *Royalties, Rentals and Bonuses; Drilling Requirements.*—The terms which a landowner may exact for a lease depend upon the prospects for securing production. If his land is remote from productive acreage and the presence of oil beneath the tract is uncertain, he may have to be content with a small royalty on the future production; that is, the lease may be granted without any immediate cash consideration or bonus. On the other hand, if the land in question is near productive territory and the structural conditions seem favorable, the landowner will be in a position to demand an initial payment in addition to a substantial royalty. Both parties to the agreement naturally want to secure the most favorable terms. The landowner being, as a rule, more or less unfamiliar with the business of oil development, and susceptible to the popular conception that huge profits are the rule, is apt to be unappreciative of the risks involved and the great cost. He accordingly is inclined to demand more than the lease is worth. The bonus demanded may be anything up to $1,000 or more per acre, and royalties range from 5 per cent of the gross value of the oil up to 50 per cent. A balance agreeable to the landowner must be determined between the bonus offered and the royalty, for the two are inter-related. Some owners prefer to have a large initial payment and a smaller percentage of the profits in the event of success, while others will be willing to share the risks and receive a smaller bonus and a larger royalty. In general, the lessee prefers to offer a higher royalty in lieu of a large bonus, since this arrangement reduces his preliminary outlay that is sacrificed in case the property is unproductive. A one-eighth royalty, or 12½ per cent, is probably specified more frequently than any other, though one-tenth, one-fifth and one-quarter are also common; however, seldom more than one-fifth is offered by a careful leaser. The higher royalties lead to early abandonment of the property, for as the production declines, the royalty payments

*Printed copies of this form may be secured from the Oil Age Publishing Co., Los Angeles, Cal.

Lease

THIS INDENTURE OF LEASE, made and entered into this________________________

day of________________________19_____, by and between________________________

____

____

hereinafter called the Lessor (whether one or more), and________________________

____

hereinafter called the Lessee,

Witnesseth

That the Lessor, for and in consideration of Ten Dollars to him in hand paid, the receipt whereof is hereby acknowledged, leases to the Lessee, all those certain pieces or parcels of land situate in the County of________________________, State of California, and more particularly described as follows, to-wit:

Said lease shall be on the following terms and conditions

1. Said lease shall continue for a period of twenty years from and after the date of this agreement, and so long thereafter as oil or gas may be produced on the demised premises in paying quantities.

2. The Lessee shall have the sole and exclusive right of prospecting demised premises and drilling for and removing oil and gas therefrom, and to establish and maintain on said premises such tanks, boilers, houses, engines and other apparatus and equipment, power lines, pipe lines, roads and other appurtenances which may be necessary or convenient in the operation or production of oil or gas from said property The Lessee shall have the right during the term of the lease to drill for and develop such water on said premises as it may require in its operations

3. The Lessee agrees to start the drilling of a well for oil within________________from the date of this agreement, and to continue the work of drilling such well after commencing the same with due diligence until a depth of__________feet has been reached, unless oil is discovered in quantities deemed paying quantities by the Lessee at a lesser depth, or unless such formations are encountered at a lesser depth as will indicate to the geologist of the Lessee that further drilling would be unsuccessful

4. After discovery of oil in said paying quantities in the first well, the Lessee agrees to commence the drilling of a second well within ninety (90) days thereafter, and thereafter continuously operate one string of tools, allowing ninety (90) days between the completion of one well and the commencement of the next succeeding until__________wells have been drilled, including offset wells Nothing herein shall be considered to limit the number of wells which the Lessee may drill, should it so elect, in excess of the number hereinabove specified

5. The Lessee may at any time before discovery of oil on the demised premises quitclaim the said property or any part thereof to the Lessor, his successors or assigns, and thereupon all rights and obligations of the parties hereto one to the other shall thereupon cease and determine as to the premises quitclaimed.

6. After discovery of oil, the Lessee may at any time quitclaim any part of said land to the Lessor, his successors or assigns Upon the quitclaiming of any part of the land to the Lessor, his successors or assigns, drilling requirements shall be reduced pro rata according to acreage On the expiration of the twenty year period, no further wells shall be drilled upon said property and all rights of the Lessee therein shall cease, except that the Lessee shall have the right to operate, deepen, redrill and properly maintain all producing wells upon the property at that time, and to use so much of the surface of the land as may be necessary or convenient for such operations Except as herein provided, full right to said land shall revest in the Lessor free and clear of all claims of the Lessee, except that the Lessor, his successors or assigns, shall not drill any well on said land within an area of ten acres surrounding each producing well

7. In the event of the discovery of oil in any well on adjacent properties within one hundred and fifty feet of the boundary lines of the demised premises, and the production of oil therefrom in paying quantities for a period of thirty days, then the next well to be drilled hereunder shall be so placed to offset said well on the adjacent property, or if no well is being drilled and the total well requirements of this lease have not been fulfilled, then within ninety days thereafter a well shall be commenced by the Lessee to offset such producing well on the adjacent property.

8. Drilling and pumping operations shall be suspended on said property only in the event that they are prevented by the elements, accidents, strikes, lockouts, riots, delays in transportation or interference by state or federal action, or other causes beyond the reasonable control of the Lessee, or so long as the price of oil of the quality produced on said property shall be less than seventy-five cents a barrel at the well.

9. The Lessee may extend the period of commencing the first well for an additional period of ________________by paying to the Lessor a rental of $________________per month for the first__________months of said additional period and $________________per month for the next__________months of said additional period, which said rental shall cease when drilling operations are commenced or the property quitclaimed

10. The Lessee shall have the free use of so much of the oil, water or gas produced on said property as may be required in the operation of the property

11. Other than the oil specified in paragraph 10 hereof, the Lessee shall pay as a rental or royalty for the use of said land one__________of all oil produced and saved thereon, said payment to be made in money or in kind at the Lessor's option If the rental is paid in kind, the oil shall be delivered into tanks maintained on the property for that purpose as produced, and shall be stored at the Lessor's risk for a period not exceeding thirty days without charge If the royalty is paid in money, then the

Lessee shall pay to the Lessor on the 20th day of each and every calendar month one__________of the market price at the well of all oil removed from said property during the preceding calendar month. The option to the Lessor to take the royalty in money or in kind shall only be exercised once every six months, and then on thirty days' notice in writing to the Lessee. If no notice is given, it shall be deemed that the royalties are payable in money

12 The Lessee shall be under no obligation to store or sell gas or water. If any gas or water is sold, then on the 20th of each and every month, the Lessee shall pay to the Lessor one__________ of the proceeds of all gas or water sold during the preceding calendar month If casing head gasoline is manufactured on the premises or elsewhere by the Lessee from gas produced in said wells, then the Lessee shall pay to the Lessor one__________of the proceeds of the sale of said gasoline, less the cost of producing and selling the same

13 The Lessee shall pay all taxes on its improvements and__________of the increase of the taxes resulting from the discovery of oil on the said property, and of all oil stored on said land on the first Monday in March. The Lessee is hereby authorized to pay all the taxes on said land and improvements, and deduct the Lessor's share thereof from the amount of royalties which shall fall due.

14 All payments to the Lessor shall be made by paying the same to the__________
__________Bank at__________

15. A well in paying quantities is hereby defined as a well which, after being pumped continuously for a period of thirty days, shall produce at least one hundred barrels of oil per day

This definition shall not apply to wells to be operated on the expiration of the twenty year period or on the abandonment of a portion of the premises, and in such case, the Lessee may operate such wells as the Lessee in its discretion shall deem sufficiently productive to operate

16 The Lessee shall carry on all operations in a careful, workmanlike manner, and in accordance with the laws of the State of California. The Lessee shall keep full records of the operations and of the production and sales of products from said property, and such records and the operations on the property shall be at all reasonable times open to the inspection of the Lessor Whenever requested by the Lessor, the Lesse shall furnish to the Lessor a copy of the logs of all wells drilled on said property.

17. The Lessor shall have the right to the use of the surface of said land for agricultural and grazing purposes to such an extent as will not interfere with the proper operation of the Lessee for oil The Lessee agrees to conduct its operations so as to interfere as little as is consistent with the economical operation of the property for oil with the use of the land for agricultural, horticultural or grazing purposes, and agrees to pay for any damage which may be done to growing crops or fruit trees through its negligence. If any of the fences existing on said lands are cut by the Lessee for its purposes, the Lessee shall establish a good and substantial gate at such point Whenever required by the Lessor in writing, the Lessee shall fence all sump holes and other openings to safeguard cattle which may be grazing on said land

18. The Lessor may have the use of any water or gas developed on said property for his domestic purposes, so long as the same is not required by the Lessee or sold The transportation of such water or gas shall be taken at a point to be indicated by the Lessee and carried to the point of use at the cost and sole risk of the Lessor

19 The Lessee shall have at any time the right to remove any houses, tanks, pipe lines, structures, casing or other equipment, appurtenances or appliances of any kind brought by it upon said land, whether affixed to the soil or not, provided, however, that in the case of an abandonment of any well, if the Lessor shall desire to retain the same as a water well, he may notify the Lessee to that effect and thereupon the Lessee shall leave such casing in the well as the Lessor shall require, and the Lessor shall pay to the Lessee fifty per cent (50%) of the cost of such casing in the ground.

20 In the event of any dispute as to any of the terms of this lease, or the performance of any of the conditions thereof by the Lessee, the same shall be submitted to arbitration. One arbitrator shall be appointed by each of the parties hereto, and a third arbitrator by the two so appointed. Any decision by a majority of such arbitrators shall be binding upon both parties

21 In the event of any breach of any of the terms or conditions of this lease by the Lessee, and the failure to remedy the same within sixty days after written notice from the Lessor so to do, then, at the option of he Lessor, this lease shall forthwith cease and determine, and all rights of the Lessee in and to said land be at an end

22 Any notice from the Lessor to the Lessee may be given by sending the same by registered mail addressed to the Lessee at__________ and the Lessee or its successors or assigns may at any time, by written notice to the Lessor, change the place of giving notice, and after such written notice to the Lessor by registered mail, the Lessor shall send all notices intended for the Lessee or its successors or assigns, to the address which may be so indicated.

23. Any notices from the Lessee to the Lessor may be given by sending the same by registered mail addressed to the Lessor at__________

24. All work done on the land by the Lessee shall be at the Lessee's sole cost and expense and the Lessee agrees to protect said land and the Lessor from claims of contractors, laborers or material men and the Lessor may post and keep posted on said lands such notices as he may desire in order to protect said lands against liens.

25. On the expiration of this lease, or sooner termination thereof, the Lessee shall quietly and peacefully surrender possession of the premises to the Lessor and deliver to him a good and sufficient quit claim deed and shall so far as possible cover all sump holes and excavations made by it and restore the land as nearly as possible to the condition in which it was received.

26. The Lessee agrees that no well shall be drilled within__________feet of any dwelling house now on said premises without the written consent of the Lessor.

This lease shall run to and be binding upon the successors and assigns of the parties hereto.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed the day and year first above written

rapidly diminish the profits. Because of this difficulty, many lessees advocate a sliding royalty in which the percentage paid decreases as the production declines. For example, it may be provided that for wells producing 25 bbl. per day, or less, a royalty of one-eighth will be paid; for wells producing from 25 to 100 bbl. per day, one-sixth; for 100- to 200-bbl. wells, a royalty of one-fifth; and for over 200 bbl., one-quarter.

For gas wells, the royalty may be based on a percentage of the gross volume, as in the case of oil; though on account of the difficulty of metering the gas, many leases call for an annual rental ranging up to $150 per well. Cognizance may be taken in the lease of the added profit which results in extracting gasoline from natural gas, claiming a portion of such profit for the lessor.

Rentals are often inserted in leases, in addition to other considerations, as a means of preventing delay in development. It may be provided, for example, that until such time as a productive well or a specified number of wells are drilled, the lessee shall pay an annual rental of a stated amount per acre, often $1. In addition, the terms of the lease usually designate a time within which drilling must be commenced, and another time within which a well must be completed to a specified depth or stratigraphic horizon.

In return for the privilege of drilling and producing oil, the lessee is able to offer the landowner certain very definite and attractive inducements. In addition to a preliminary monetary consideration, the owner becomes a partner in the business with a preference right to a fair percentage of any profits that may result. His land is tested by the drilling of a well which costs him nothing, and he may prescribe conditions which will insure himself against damage or loss of any sort. He shares liberally in the profits, and risks nothing.

Leasing Practices.—The prospector must often obtain several leases to adjoining properties in order to secure sufficient territory to remunerate himself adequately in the event that his well is successful. In order to accomplish this without stimulating lease values by his efforts, the operator often adopts a secretive policy, perhaps acting through a local agent having the confidence of the people with whom he has to deal. This method is particularly common with some of the larger oil companies who often desire to keep their identity unknown until all necessary acreage is under lease. In many cases, certain landowners will refuse to lease in the hope of securing more attractive terms in the event of oil discovery. Most of the larger oil companies have land and lease departments with certain officials employed whose duty it is to secure leases to such land as the geological department and the directing officials may designate as desirable.[1] With the smaller companies this work is often done by the field geologists. The larger companies also employ "scouts," often trained geologists or skilled "leasers," who maintain a close watch on

the activity of other operators and on "wildcatting" and new development. Such men are often shrewd judges of property values and by prompt action secure choice acreage at favorable prices.

If a profit can be secured, a lease is often sold by the original lessee before a well is drilled. In fact, many individual speculators secure leases during the early period of development of a new field, with the expectation of selling them to producing companies who are often too conservative to interest themselves in the more speculative aspects of the industry. In some cases, leases have changed hands several times before any drilling is done. The original lessee in selling his lease may secure a bonus greater than that which he paid for it, or retain an interest in the property as a partner or stockholder. Occasionally, an additional royalty payable to the original lessee may be exacted.

In a new field under active development there is also a considerable trade in lease royalties. The original property owner, anxious to realize on his expected profits, may be induced to sell his royalty interest for a sum which is sufficiently below the prospective income to form an attractive speculation for the buyer. Purchase of royalty interests by officials of the company owning the lease is quite common, though the ethics of such practice is sometimes questionable.

Legal Aspects of Oil and Gas Land Leasing.—To be valid, a lease must be properly acknowledged and signed before a notary public or other authorized public official, by both parties. If the property leased is a homestead and the owner is married, the wife's signature is also essential. The tract must be carefully described in the lease, if possible with reference to public land subdivisions, or by metes and bounds with reference to some definite landmark. As protection to the lessee against the possibility of the lessor dishonoring his agreement or issuing a second lease to another party, the instrument should be filed with the county recorder or county clerk.

The permanence of the lease is conditional upon the discovery of oil or gas in paying quantity; that is, the relation created is that of a conditional tenancy, but the discovery of oil or gas in the leased premises vests in the lessee the right to make future exploration, and to develop, produce and sell the mineral so discovered.[2] That is, after the discovery of oil, the lessee's right is no longer conditional, and the relation of landlord and tenant is created until the end of the term fixed by the lease. The completion of an unsuccessful well does not necessarily terminate the lease, for it is ordinarily the obligation of the lessee and the right of the lessor that development shall continue. Though there may be a clause in the lease definitely limiting the duration in the event that a well is not drilled, or oil is not discovered, it is usually provided that if production is secured the lease shall continue as long as oil or gas is produced in paying quantities. In some leases, however, the period of production under the

lease is limited by a definite number of years, always sufficient, however, to permit the lessee practically to exhaust the property.

It is usually provided that the lessee may surrender the lease at any time, if he so desires, and be relieved of any conditions to which it obligates him. Such surrender may require payment of a sum of money, however, if so stated as a condition in the lease. The lessor has no corresponding privilege of compelling a surrender unless the lessor defaults in some of the expressed terms. A lessee is not obligated to continue operation of a lease after it has become unprofitable to himself, though it may still be profitable to the lessor. It is only when manifestly fraudulent use of opportunities and control can be shown that courts are authorized to interfere between lessor and lessee.

Oil and gas leases frequently contain clauses designed to insure prompt commencement of drilling operations. Even in the absence of an expressed agreement, when a lessee undertakes to develop oil or gas on a rental or royalty basis, and the agreement does not specify the number of wells to be drilled, there is an implied obligation that the land will be fully developed with reasonable diligence. Under certain conditions, where a lease contains a provision permitting a lessee to pay a stipulated rental for delay in beginning drilling operations, the lessor may refuse to accept the rental and require the lessee to develop the property within a reasonable time or forfeit the lease. The phraseology of the lease has a determining influence on the right of the lessor in this connection. For example, in Oklahoma, if it is specified that a well is to be drilled within a certain time *unless* the lessee pays the lessor a stipulated rental, the lessee may terminate the lease by failure to pay rental; but the lessor may not do so as long as the rental is paid. If the word "or" is used instead of "unless," the lease is not necessarily terminated unless the lessor claims the forfeiture.[1]

If a lease is assigned by the lessee to another for a valuable consideration, the assignee legally assumes all of the conditions, implied or expressed, and is liable for all obligations maturing during his tenancy.

To be legal, a lease must possess "mutuality." In several instances where leases have provided for no bonus, and where no obligation to pay any penalty for surrender of the lease is expressed, it has been held by the courts that the arrangement was terminable at the pleasure of either party. The question of whether or not some nominal sum, such as $1, is a sufficient consideration to support a lease of this character has led to diverse opinions in different jurisdictions.

In the absence of contrary expression in the lease, the lessee has only such rights to the surface of the leased land as may be necessary to the exercise of his right to extract the oil and gas. He must give adequate protection to the lessor's property, and is liable for damages if he fails to do so. Where the lessee has in part developed a property held under

lease by the drilling of productive wells, and has failed to offset wells on neighboring properties to prevent drainage, the lessor may secure damages from the lessee in lieu of the additional royalties that he would otherwise receive; but if no wells have been drilled on the premises the lessor has no recourse beyond the time limits set by the lease for the drilling of the initial well.

SELECTED BIBLIOGRAPHY ON SUBJECT MATTER OF CHAPTER II

1. JOHNSON, HUNTLEY and SOMERS: "Business of Oil Production," John Wiley & Sons, N. Y., 1922. See particularly Chaps. II to VII, inc.
2. MCKINNEY and RICH (editors): "Ruling Case Law," Bancroft, Whitney & Co., San Francisco. See particularly, vol. 18, pp. 1205–1219, 1917, and Supp., vol. 3.
3. THOMPSON, J. W.: Petroleum laws of all America, U. S. Bureau of Mines, *Bull.* 206, 1921.
4. U. S. General Land Office, Dept. of Interior, Regulations concerning oil and gas permits and leases including relief measures and rights of way for oil and gas pipe lines, *Circular* 672, 1920.
5. VAN WAGENEN, T. F.: "International Mining Law," McGraw-Hill Book Co., N. Y., 1918.

CHAPTER III

MAPS AND SECTIONS; GRAPHIC LOGS AND PEG MODELS

In view of the vast amount of capital expended in developing oil fields, and the value of the information relative to underground conditions gained as a result of such work, it is evident that a thorough, well-planned and coordinated series of maps and drilling records is essential. Such records are indispensable in the conduct of future development work, in diagnosing production troubles, in planning well repairs, in making appraisals and in other similar engineering problems. So important do many operators consider this matter, that they employ engineers or geologists to keep the drilling records under constant surveillance, so that no detail of the work will be overlooked.

The records maintained should include field property maps, showing the location of wells with respect to property lines, elevations of derrick floors and initial productions of oil, gas and water for each well. Well logs and histories, peg models, casing records, fluid levels in wells and water analyses have an important bearing on the work. Such records are used also in developing geologic evidence in the form of structure contour maps, convergence maps, cross-sections and stereograms. Cost records and progress records may also constitute a part of this program. The drilling records should also include actual physical samples of the formations penetrated, consisting either of carefully washed sands or solid cores. Samples of waters encountered at various depths may also be preserved for future reference unless detailed analyses of the waters are made a part of the drilling record.

Field Maps.—Field maps are constructed by first drawing a map of the property lines, together with the railroads, highways, town sites and other permanent improvements, in as much detail as desired, or as the scale of the map will permit. Ownership of various properties, section and township lines and numbers are also carefully lettered. Using this base map as a frame, all wells are then located to scale with reference to property lines or section corners. The position of each well is indicated by a small circle, using conventional symbols (see Fig. 17) in connection therewith, to indicate whether the well is a drilling well, a producing oil well, a gas well, a dry hole, a well abandoned in process of drilling, a well temporarily idle or an abandoned producer. The number of the well, or the name by which it is known, is lettered at one side of the symbol marking its position, and if the scale of the map permits, the

elevation of the derrick floor and the depth of the well may also be indicated; and perhaps, also, the initial production.

Fig. 18 illustrates a typical field map. It is obvious that to serve its intended purpose, which is primarily to show in a broad way the extent of development in different portions of the field, the map must be of rather small scale, otherwise it becomes unwieldy. Scales of 2,000 or 1,000 ft. to the inch are commonly used for this type of map.

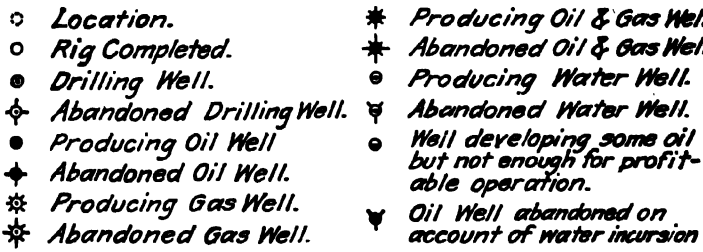


FIG. 17.—Conventional symbols for oil field maps.

These are large enough to permit of showing the positions of the wells, their numbers, names of property owners, etc., but do not allow space for much further detail.

Property Maps.—Maps of larger scale, often 200 or 300 ft. to the inch, afford opportunity for indicating the position of wells, derricks and rigs, buildings, tanks and reservoirs, pipe lines, roads, telephone lines, fences and other structures in full detail. Such maps are called "property maps" to distinguish them from the smaller scale field maps. The map shown in Fig. 19 is typical.

Well Logs.—Of the various records concerned with well data, none are more important than the log of the well. The log should give a complete history of the well from the time of its location until its abandonment. Every detail of the drilling procedure should be made a matter of record; the well equipment; the thickness, nature and depths of strata penetrated; depths at which oil, gas and water of special characteristics are encountered; depths at which casings are landed and water shutoffs made; water shutoff tests and names of witnesses; dates of starting and completion of drilling; names of drillers, tool dressers and others employed in the work; explosives used and depths at which used; pumping tests; initial production of oil, gas and water; and rating after 30 days' production. Repair work, redrilling jobs, alterations and important replacements of the well equipment, work involved in abandonment, etc., should be added to the original drilling record from time to time as such work is performed.

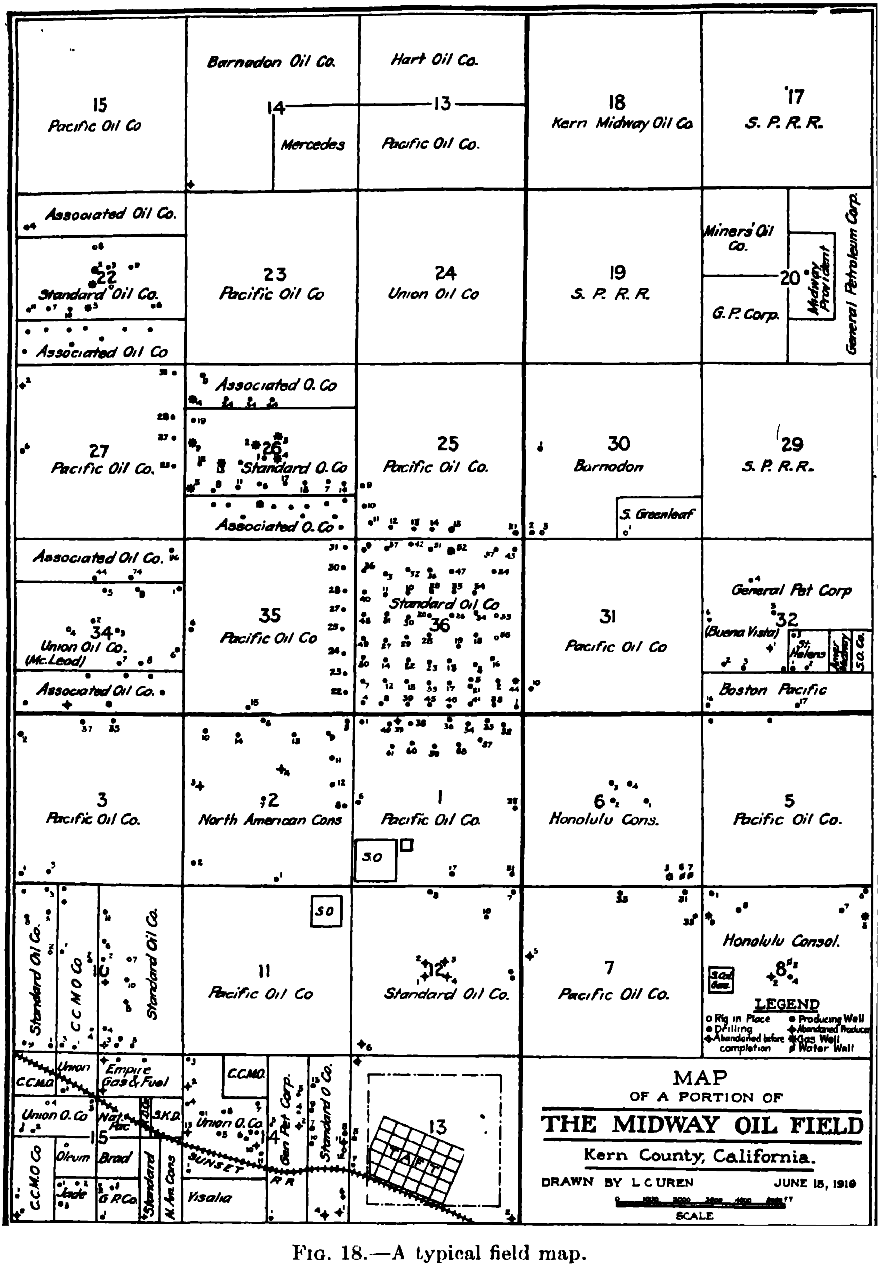


FIG. 18.—A typical field map.

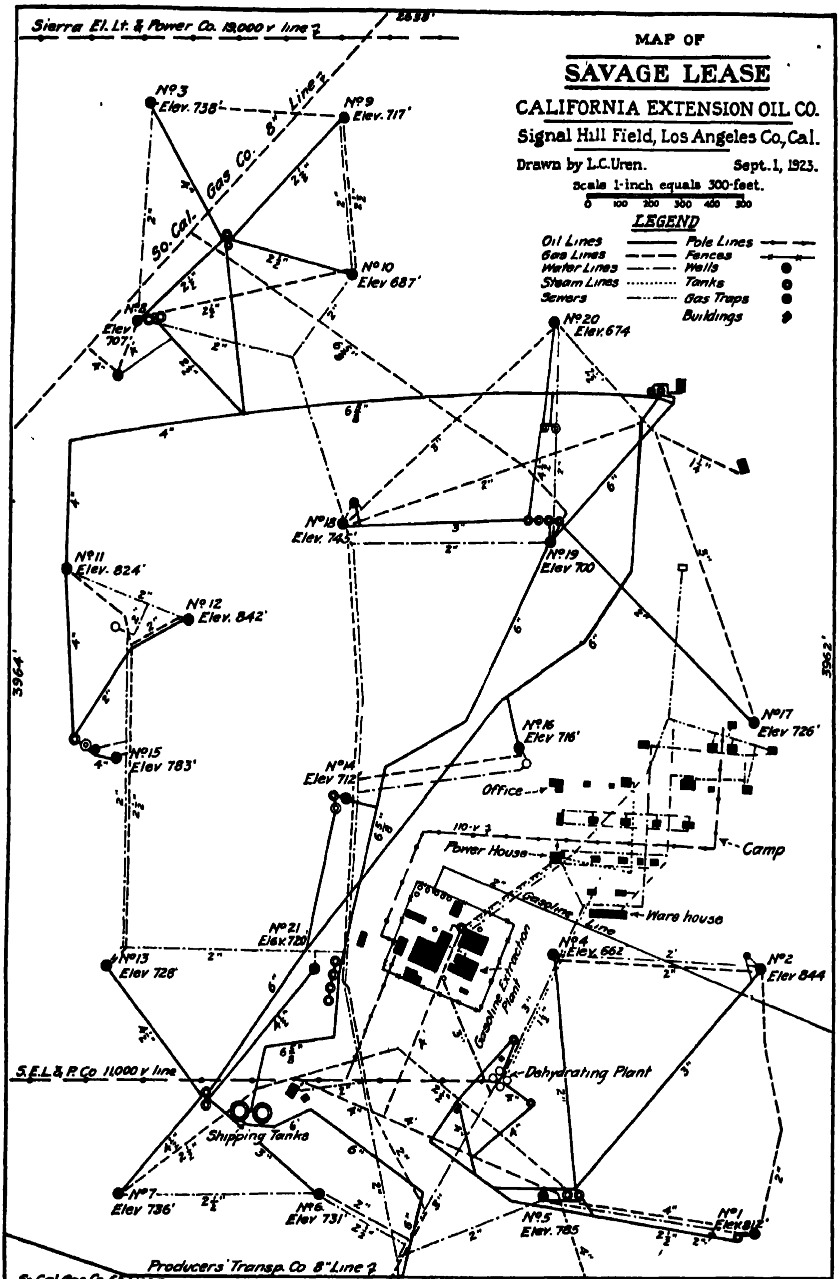


FIG. 19.—A typical property map.

The property is only partially developed. Wells produce both oil and gas and are operated by individual gas engines. Buildings may be conveniently numbered, with reference to a list giving purpose and dimensions of each.

This data should be arranged in chronological sequence except for the stratigraphic record, which should be maintained in a separate table arranged in depth sequence. It is customary to classify this data under several different headings for convenience in reference. We may have one section devoted to the location of the well; another to the stratigraphic record; one to the chronological record of the original drilling; another to subsequent history; and still other sections will be concerned with the casing record, depths of oil and gas sands, water sands and water shutoff methods and tests. The log form* given on pages 61 and 62 is typical.

Graphic Logs.—We may indicate much of this data with the aid of various conventional symbols on a graphic log, which is more desirable for certain purposes than the written historical record. Most operators will find it desirable to preserve the well record in both written and graphic form. The graphic record, plotted to vertical scale as illustrated in Fig. 20, is particularly valuable in that it conveys quite readily by pictorial means, facts which can only with difficulty be made strikingly apparent in the ordinary form of written record. For example, it conveys a true impression of relative depths, thicknesses of strata encountered in the well and their sequence, and indicates the manner in which the well is cased to better advantage than is possible in the written record. There are no conventional well log symbols that are yet recognized as standard, but those suggested in Fig. 21 have been adopted by the State Mining Bureau of California[2] and have found wide application in drilling records in that State. The author has compiled the somewhat more complete group of conventional symbols given in Fig. 22 from several sources.

In selecting symbols for use on well logs, considerable time and expense may be saved by using simple forms that can be readily applied. They should, however, be sufficiently distinctive so that no confusion in interpreting them will result. Predominating rocks, such as shale or sandstone, may be left blank. Rock colors may be indicated in connection with the conventional forms representing different types of rocks, by the use of the suitable abbreviations. The fluid content of the formations penetrated—either oil, gas or water—must also be indicated at the proper scale depths. Oil may be represented by solid black applied over the entire stratum in which it occurs, if present in quantity, or in irregular patches on the formation graph if only slight "shows" are in evidence. Water and gas are conveniently indicated by their initial letters placed at one side of the stratigraphic record. It is customary to indicate the depths to the top and bottom of all oil and gas sands, as well as important marker horizons and reference points, by the use of small figures placed at one side of the formation record.

The casing record forms an important part of the graphic log. This usually consists of a series of vertical lines about $\frac{1}{8}$ in. apart, placed at one side of the formation graph, one line being drawn for each "string" of casing placed in the well. The landing depths should be indicated by terminating each vertical line at the proper

* After A. W. Ambrose in U. S. Bureau of Mines, *Bull.* 195.

SPECIMEN WELL-LOG RECORD

(FRONT SIDE.)

FIELD *Coalinga* COMPANY *California Oilfields, Limited (Shell Co., of California)*

LOG OF WELL NO. *78*

DESCRIPTION OF PROPERTY *(Quarter Section) S. W. ¼ of Sec. 27, 19/15*

LOCATION OF WELL *740′ N. and 2905′ W. of S. E. corner*

ELEVATION ABOVE SEA LEVEL *1178 Feet*

COMMENCED DRILLING *Oct. 29, 1913.* FINISHED DRILLING—*See History*

Depth from—	To—	Feet.	Formation.
0	10	10	Brown adobe.
10	25	15	Brown sand.
25	55	30	Yellow clay.
55	65	10	Coarse gray sand.
65	98	33	Black gravel.
98	125	27	Brown sand.
125	185	60	Blue sandy shale.
185	210	25	Light blue shale.
210	245	35	Coarse gray sand.
245	315	70	Light blue shale.
315	317	2	Brown shale.
317	330	13	Blue shale.
330	390	60	Sandy blue shale.
390	404	14	Fine gray sand.
404	440	36	Light green shale.
440	450	10	Gray sand.
450	478	28	Coarse gray sand and gravel.
478	497	19	Gray sandy shale.
497	510	13	Coarse gray sand.
510	535	25	Sandy blue shale.
535	580	45	Blue shale.
580	640	60	Sandy blue shale.
640	690	50	Gray sand, **shows tar oil.**
690	705	15	Blue shale.
705	715	10	Sandy blue shale.
715	723	8	Gray sand, **shows tar oil.**
723	733	10	Fine hard gray sand.
733	740	7	Hard sand shell.
740	753	13	Gray sand, **shows tar oil.**
753	757	4	Blue sand shell.
757	785	28	Soft gray sand.
785	796	11	Blue shale.
796	797	1	Hard sand shell.
797	805	9	Soft sand and gravel, **Water.** (Water stands at 600′.)
805	806	1	Hard sand shell.
806	870	64	Sticky blue shale.
870	905	35	Fine gray sand.
905	920	15	White sand and sea shells. (Put in 2 loads red mud at about 930′.)
920	965	45	Soft gray sand.
965	985	20	Sandy blue shale.
985	1,005	20	Sandy shale, black.
1,005	1,055	50	Fine soft gray sand.
1,055	1,092	37	Hard coarse gray sand.
1,092	1,104	12	Sticky black shale.
1,104	1,129	25	Sticky light blue shale.
1,129	1,140	11	Light gray slate.
1,140	1,214	74	Tough green shale. **(12½″ casing cemented at 1214′.)**
1,214	1,232	18	Tough, sticky green shale.
1,232	1,280	48	Light green shale.
1,280	1,295	15	Light blue shale.
1,295	1,305	10	Light gray shell.
1,305	1,330	25	Sticky blue shale.
1,330	1,348	18	**HARD GRAY OIL SAND, fair**
1,348	1,363	15	**FINE GRAY OIL SAND, good.**
1,363	1,380	17	Hard gray sand, no oil.
1,380	1,393	13	**SOFT GRAY OIL SAND.**
1,393	1,410	17	Hard gray sand, no oil.
1,410	1,421	11	Black sandy shale.
1,421	1,423	2	Hard sand shell.
1,423	1,440	17	Fine black sand.
1,440	1,445	5	Hard sand shell.
1,445	1,470	25	Fine dark gray sand.
1,470	1,493	23	Sandy blue shale. **(10″ casing cemented at 1626′.)**
1,493	1,495	2	Hard sand shell.
1,495	1,500	5	Very sandy shale, **shows oil and gas.**
1,500	1 510	10	Soft fine gray sand, **shows oil.**
1,510	1,525	15	Light blue shale.
1,525	1,587	62	Gray sand, **shows oil and gas.**
1,587	1,598	11	Black sandy shale.
1,598	1,608	10	Hard fine gray sand, no oil.
1 608	1,620	12	Fine black sand, shows **Sulphur Water.**
1,620	1,629	9	Tough black shale.

a Original, 8½ by 21½ inches in size.

SPECIMEN WELL-LOG RECORD (*Continued*)

(Reverse side.)

(LOG CONTINUED.)

HISTORY OF ORIGINAL DRILLING.

Casing froze at 1353′. Bailed to free the 10″ casing and bailed dry. No record concerning water (12/15/13). Put in red mud, drilled ahead, finding 40′. Cavings in hole (12/16–18/13).

10″ casing cemented at 1497′ with 56 sacks cement dumped in (12/24/13). Cement 10′ in casing, but bailed out 5′. Cement set to Mar. 16, 1914. Bailed hole dry, stood 6 hours and made no water. Drilled pocket to 1517′, bailed hole dry, stood overnight and made 2 pails of water and a little oil. Then started to put in 8¼″ casing. Drilled hole to 1620′; well showed evidence of sulphur water.

8¼″ casing. Had in 1581′ of 8¼″ casing and then pulled two joints and bailed hole dry, stood 5 hours, and made 168′ of water and no oil. Bailed hole dry and sand filled hole up to 1550′. Bailed at 1-hour intervals and well made 5 bailers (6⅝″ by 40′) each run of black water, "smelling strongly of sulphuretted hydrogen. There is also a little oil" (3/24/14).

Bailed, hole made 6 bailers per hour of water with a little tar oil. Made 10 bailers after standing 2 hours (3/25/14). Bailed hole, made 5 bailers per hour of black sulphur water with a little tar oil (3/26/14). Bailed; no change in quantity of water or oil (3/27–30/14).

Pulled so as to loosen 10″ casing and cement it lower in order to shut off sulphur water (3/31/14).

10″ casing. Got 10″ vibration at 1425′. Filled hole from 1501′ to 1497′ with brick and cement. Put in 5 sacks cement and drove two wooden plugs into cement, top of plugs at 1490′. Dumped in 10 sacks cement and drove two wooden plugs, filling hole to 1462′.

Ripped 1425′ to 1455′ and filled hole to 1385′ with 19 sacks cement, broken concrete, M. & F. plugs. Dumped in wheelbarrow load of gravel and ripped 10″ casing at 1345′ to 1370′. Put in 4 sacks cement, filling hole to 1365′.

Pulled 1335′ (4/11/14), left 162′. 1335′ to 1497′ to be cased off. Drilled to 1395′ and found tools following old hole. Filled to 1370′ with bricks and 8″ by 8″ timbers, then drilled past casing to 1629′. Reamed to 1626′.

10″ casing cemented at 1626′ (4/29/14) with 73 sacks cement dumped in. Ran in and found cement 10′ up in casing. Shut down for cement to set.

Idle until August 23, 1916.

HISTORY OF PLUGGING AND PERFORATING.

10″ casing. Drilled pocket to 1630′ (8/25/16). Bailed dry at 3-hour intervals.) Made 3½ barrels of water per hour. Tested by bailing from Sept. 30, 1916, to Oct. 1, 1916. Made 2½ barrels of water per hour.

Plugged to 1587′ feet with 50 sacks cement, Sept. 2, 1916. Perforated by machine as follows: 1330–1410; 1423–1470; 1529–1580.

Bailed. Made 29 barrels of oil in 24 hours. Small show of water, Sept. 15, 1916. Tubed at 1480′ with 3″ tubing Sept. 30, 1916.

Production. About 40 b/d and no water. Gravity 25.3.

CASING RECORD.

15½ in. landed at *834* ft., cut at (*All Pulled*) ft., weighing *70* lbs. brand *DBX* (*11/17/13*)
12½ in. cemented at *1214* ft., cut at ft., weighing *40* lbs. brand *DBX* (*12/3/13*)
10 in. cemented at *1626* ft., cut at ft., weighing *48* lbs. brand *DBX* (*4/29/14*)

OIL AND GAS SANDS.

From *640* ft. to *690* ft.	From *1380* ft. to *1393* ft.
From *715* ft. to *723* ft.	From *1500* ft. to *1510* ft.
From *740* ft. to *753* ft.	From *1525* ft. to *1587* ft.

WATER SANDS.

From *797* ft. to *805* ft.	*Water stands at 600* ft.
From *1620* ft. to *1608* ft.	

METHOD OF SHUTTING OFF WATER.

12½ in. casing cemented at *1214* ft. with *31* sacks of *GG* (*12/3/13*) cement.
10 in. casing cemented at *1497* ft. with *56* sacks of *dumped in* (*12/24/13*) cement.
10 in. casing cemented at *1626* ft. with *73* sacks of *dumped in* (*4/29/14*) cement.
From -------- -------- ---------- -------- --------

WATER TESTS.

(State how long cemented. Water level. Details of bailing and results.)

12½″ casing. Practically no cement in casing. Cemented at 1214′ (12/3/13). Set until 12/7. No record of any test.

10″ casing cemented at 1497′ with 56 sacks cement dumped in (12/24/13). Cement 10′ in casing, but bailed out 5′. Let cement set to 3/16/14. Bailed hole dry, stood 6 hours and made no water. Drilled pocket to 1517′, bailed hole dry, stood overnight and made 2 pails of water and a little oil.

10″ casing cemented at 1626′ with 73 sacks cement dumped in (4/29/14). Ran in and found cement 10′ up in casing. Shut down for cement to set.

PERFORATIONS.

Machine From.	To.	Rows.	×	Holes per foot.	*See History.*
--------	--------	--------	---	--------	--------
--------	--------	--------	---	--------	--------
--------	--------	--------	---	--------	--------

Gravity of oil *25.3* Water cut *0*	Initial rating of well *40 b/d*
Date well began prod. *Sept. 30, 1916.*	Heaving plug (material).
Remarks: (Special features not provided for above)	

At a depth of Feet

Drillers.

Harper, Brandle, Wheat.

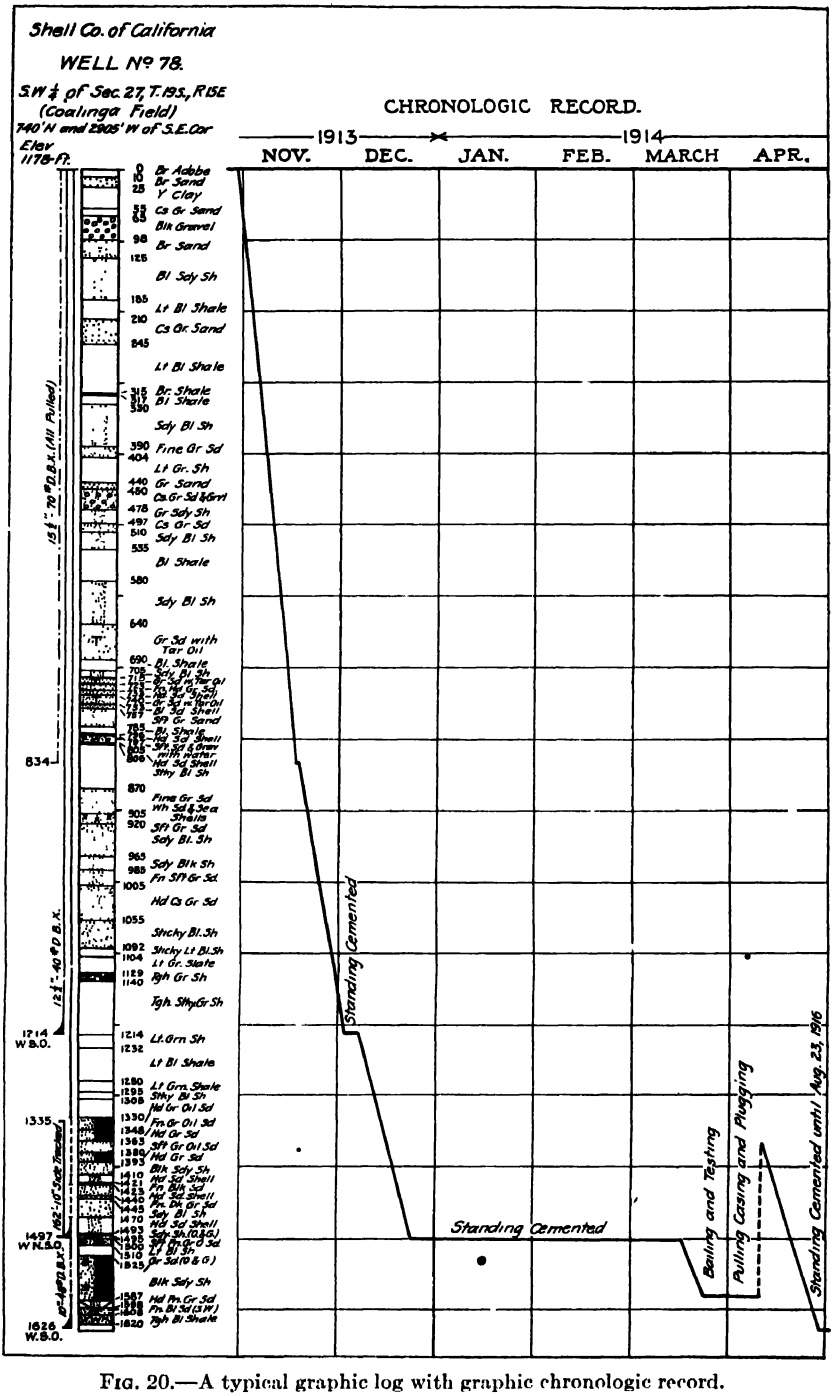


Fig. 20.—A typical graphic log with graphic chronologic record.

depth with reference to the scale used on the formation graph. A short horizontal line at this point emphasizes it more definitely, and the depth and diameter of casing should be lettered along it. When a string of pipe has been cemented, a free-hand fillet of sufficient weight to attract the attention may be applied in the angle

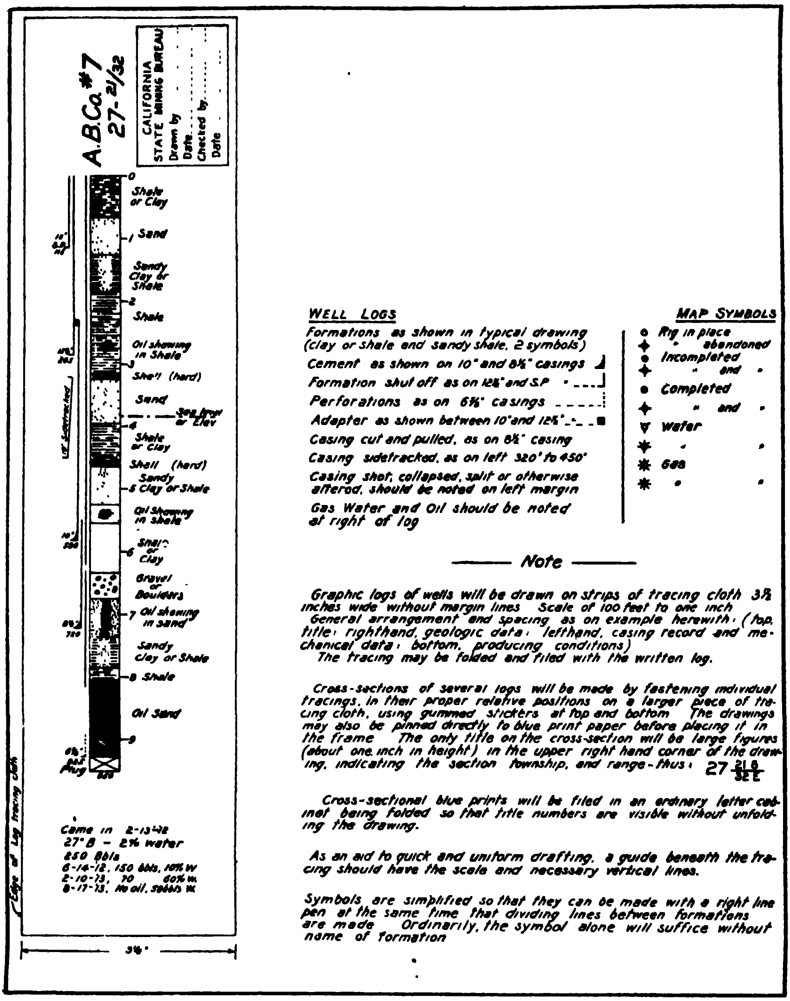


FIG. 21.—Conventional symbols for use on oil field maps and well logs adopted by California State Mining Bureau, Department of Petroleum and Gas.

formed by the horizontal and vertical lines (see Fig. 22). If tests show that water has been successfully excluded by the cement, the abbreviation W.S.O. (water shut-off) may be added, or W.N.S.O. if unsuccessful. Perforated casing or screen pipe can be indicated by dotted or dashed lines.[1]

Brief notes descriptive of the drilling operations, the results obtained and interpretations of data should be freely used, lettering them neatly at the proper point opposite the formation graph. At the top of the graphic log should be lettered the

well number, its location, elevation of the floor of the derrick and date of starting. At the bottom should appear the final depth, date of completion and the rating of the well, or its initial production of oil, gas and water. The gravity of the oil should also be given.

Graphic well logs may be conveniently constructed on strips of tracing cloth 3 in. wide and long enough to permit of plotting the entire record on a scale of 1 in. to 100 ft. This scale is large enough to show a 2- or 3-ft. stratum. Tracing cloth on which is printed a 10- by 10-in. cross-section grid is convenient, permitting the log to be constructed without the aid of a scale. However, the coordinate lines obscure to some extent the conventional symbols used. By working on the reverse side of the cloth from that on which the coordinate lines are printed, and removing the latter with alcohol or chloroform when the drawing is completed, this difficulty can be overcome. Some draftsmen prefer to use plain tracing cloth, plotting the log over a specially prepared standard form ruled with horizontal lines $\frac{1}{10}$ in. apart, which may be slipped under the tracing cloth before the work is begun.[1] Every 100-ft. interval should be indicated in this case, for convenience in reference.

Blueprinted copies of the logs are quickly made from the tracings when desired. A more pleasing result is obtained by making brown-process prints from the tracings, using these in turn to make blue-line or positive blueprints. Or, brown-process paper may also be used in making the positive prints, securing a black-line print closely resembling the original drawing. The black-line or blue-line print may be tinted, if desired, with the aid of water color or crayon, a process which greatly enhances the final appearance of the logs and gives opportunity for the use of distinctive conventional colors.

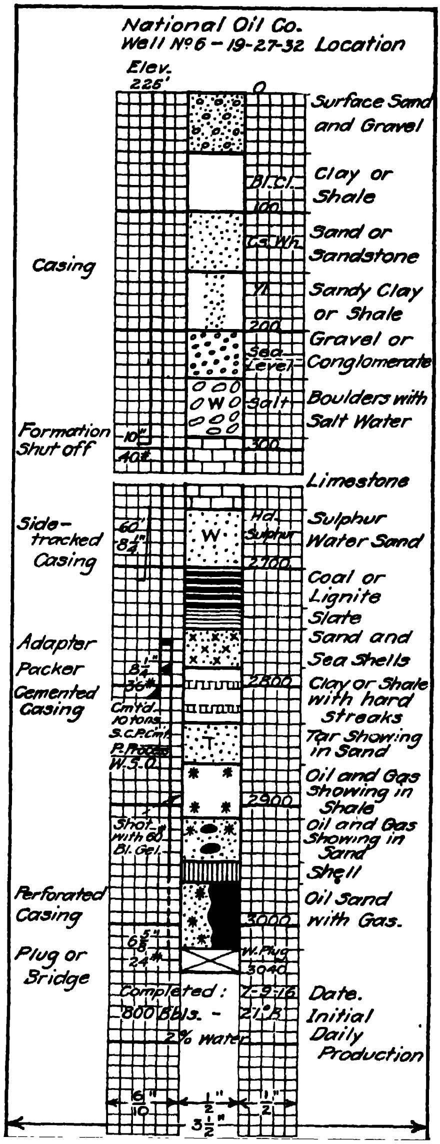


FIG. 22.—A proposed group of conventional well log symbols.

The data incorporated in the well logs must be collected, for the most part, by the drillers, though the average driller is poorly equipped for the work of identifying the mineralogical and lithological characteristics of the formations penetrated. The driller usually has at his command a limited vocabulary of colloquial rock names,

often local names, which are based on the hardness, toughness and color of the material, rather than upon any petrographic classification. However, he is usually able to distinguish such common materials as sand, sandstone, limestone, clay, shale and conglomerate, and when supplemented by descriptions of color and texture, for most purposes, this is sufficient, if carefully and accurately done. The colors recorded are ordinarily those exhibited by the wet material as it comes from the well. For more accurate technical identification, samples of each formation, carefully labeled with the depth from which they come, should be preserved in bottles for the use of the geologist.

Vertical sections on which the structural and stratigraphic features may be displayed to good advantage are conveniently constructed with the aid of graphic logs prepared as just described. Cross-sections developed in this way are most useful in studying the underground conditions in oil fields. The formations are determined by the drilling records and the cross-sections are used to correlate these formations from well to well. Even in a region of simple geologic structure and stratigraphy, cross-sections are necessary to bring out the local variations in structure. Irregularities of well depths and casing depths can also be studied to advantage with the aid of cross-sections. Cross-sections, in fact, form the basis of the work of the engineer and geologist in studying underground losses and methods of improving recovery.

The selection of the position of the cross-section involves choosing a line of wells that will give sufficient information and that lie in the desired position with respect to the axes of the structure. Usually, it is desirable to have one or more cross-sections plotted at right angles to the major axis of the structure and one parallel with the major axis. To aid in correlating, it is particularly desirable to have one or both end wells of each cross-section overlap; that is, the log of the end well should also be plotted on some other cross-section. The graphic log of every well on a property should be plotted on at least one cross-section. If it happens that a particular well falls a little to one side of a desired cross-section, it is often possible to project it into the plane of the cross-section by reference to known marker horizons, or by an actual calculation of equivalent positions with respect to the known dip of the formation. The individual logs may also be correlated by reference to an assumed datum line, such as sea level (see Fig. 23).

There are two general methods of preparing cross-sections: one in which the graphic well logs are plotted on a single piece of tracing cloth, properly spaced apart to the scale selected; and the other where the graphic logs are plotted separately on strips of tracing cloth and are arranged at proper distances apart to form the desired cross-section. In the latter plan, each graphic log has to be plotted only once, serving in turn for as many different cross-sections as may be desired.

Most engineers prefer to construct vertical sections by blueprinting from the graphic log tracings. The graphic log tracings are placed in the printing frame, properly spaced apart to an assumed horizontal scale and adjusted with respect to an assumed datum line. For convenience, we may have a horizontal line ruled on the glass against which the print is made and adjust the sea level points of all tracings so that they fall on this line. This automatically accounts for differences in elevation of the derrick floors. We may also have marks along the top and bottom of our blueprint frame to serve as a scale, which aids in spacing the logs at the proper distances apart and in keeping them in a vertical position. With a series of logs

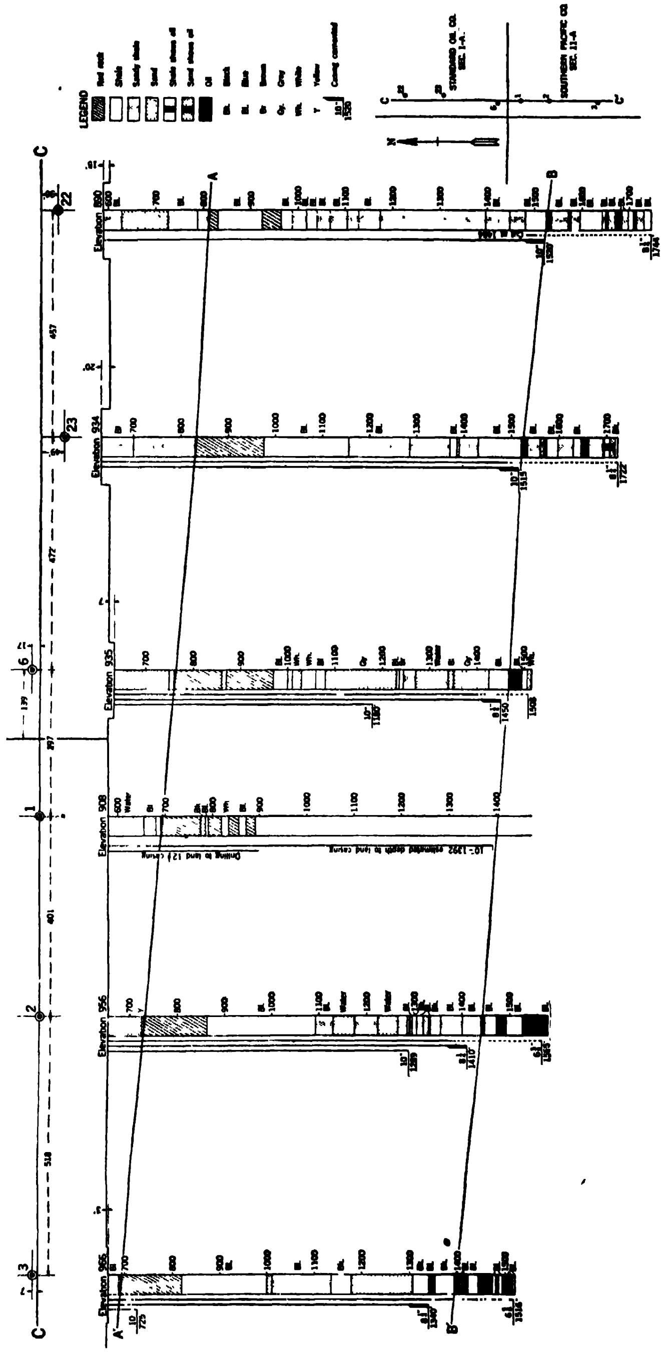


FIG. 23.—Illustrating development of geologic sections by correlation of well logs. Lines A-A' and B-B' represent correlations of marker horizons. (*After R. E. Collom in U. S. B. Mines, Bull.* 201).

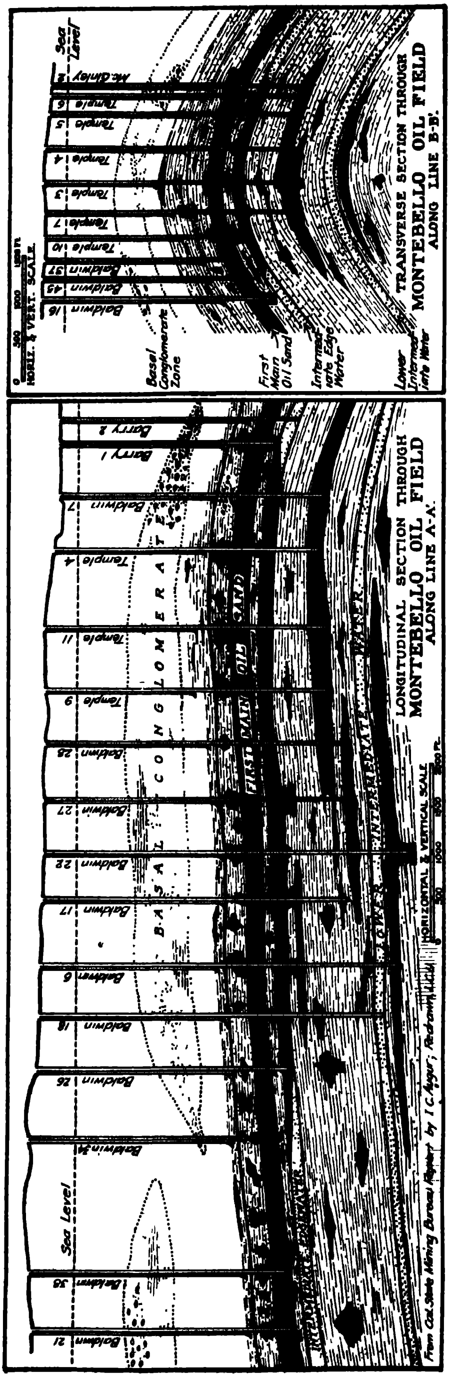


FIG. 24.—Typical geologic sections developed from well log data. Note position of these sections on structure contour map reproduced in Fig 25

arranged in the frame in this way, a blueprint is made on one sheet of paper which becomes a permanent copy of the logs as arranged. This print may be later used in developing a completed section.

In order that lines may be drawn on this section, it is desirable to use a positive or blue-line print, which, of course, necessitates the making a brown-process negative. Corresponding horizons on different wells in the cross-section are first connected with straight lines, and the intervening space between logs may then be worked up in full geologic detail if desired. The appearance is greatly improved by the use of crayon or water color applied in such a way as to develop suitable distinctions between the different strata.

Instead of blueprinting sections in this manner, we may photograph the well logs after properly arranging them to form the desired section. The photostat, a device for making photographic prints directly on bromide paper, is most useful for making the prints if this plan is followed. The photographic prints are then used as a base on which to develop the complete geologic detail if desired.

The cross-section should show the number of each well in the section, its elevation, production data, etc., and there should be a supplementary key map indicating the line of the cross-section. Every cross-section should also have a suitable title (see Fig. 24).

Underground Structure Contour Maps.—Well logs are also useful in construct-

ing what is called an underground structure contour map. Such a map shows by means of contours connecting lines of equal elevation, the position and form of an unexposed bed such as the top of an oil sand, over a large area.[5]

Before starting work on a structure contour map, the datum plane must be chosen—this is usually sea level. The contour interval must also be decided upon, and this usually depends upon the nature of the structure, its dip, the data available, the scale adopted and the purpose for which the map is to be used. The contour interval, or distance between successive contours, is frequently 25 or 50 ft.

By a study of well logs or cross-sections, the distance between the bed to be contoured and the datum plane is computed for each well and written down beside the well's position on the map. Interpolation between known points determines the elevations of other points. Contours are then sketched in at regular intervals with respect to the elevations so determined (see Fig. 25).

The chief value of such a map is to display broad structural features over a large area in a way not equalled by even the most careful study of geologic cross-sections. An underground structure contour map can often be used to show the location of wells relative to folds in the formation, or the most favorable undrilled tracts for the production of oil and gas, and it may be used as an aid in the selecting of well sites. It is also possible with a carefully prepared structure contour map to predict with fair certainty the necessary depth of a well to be drilled at any designated point to intersect the oil sand. The map also serves to indicate the direction and amount of dip of the structure at any point.

Convergence Maps.—Still another type of map that is useful in many ways, and that can be developed from well log data, is the convergence map. This type of map indicates, by means of contours, the difference in elevation at any point between two irregular and non-parallel horizons. It may show, for example, the difference in elevation between the surface of the earth and the top of a submerged oil sand. The convergence map is constructed in much the same manner as the structure contour map, calculating the distance between the two horizons at various points from the known rate of convergence and connecting points having the same difference in elevation with contour lines.

Peg Models.—The most satisfactory method of demonstrating the the structural conditions disclosed by a series of well logs, is by constructing what is called a "peg model." Peg models have a great advantage over maps and sections in that they present the data directly in three dimensions instead of two, so that we obtain an actual picture of the situation. The method has been found especially useful to the non-technical man, who grasps readily the essentials from a model, whereas cross-sections and contour maps are apt to be confusing.

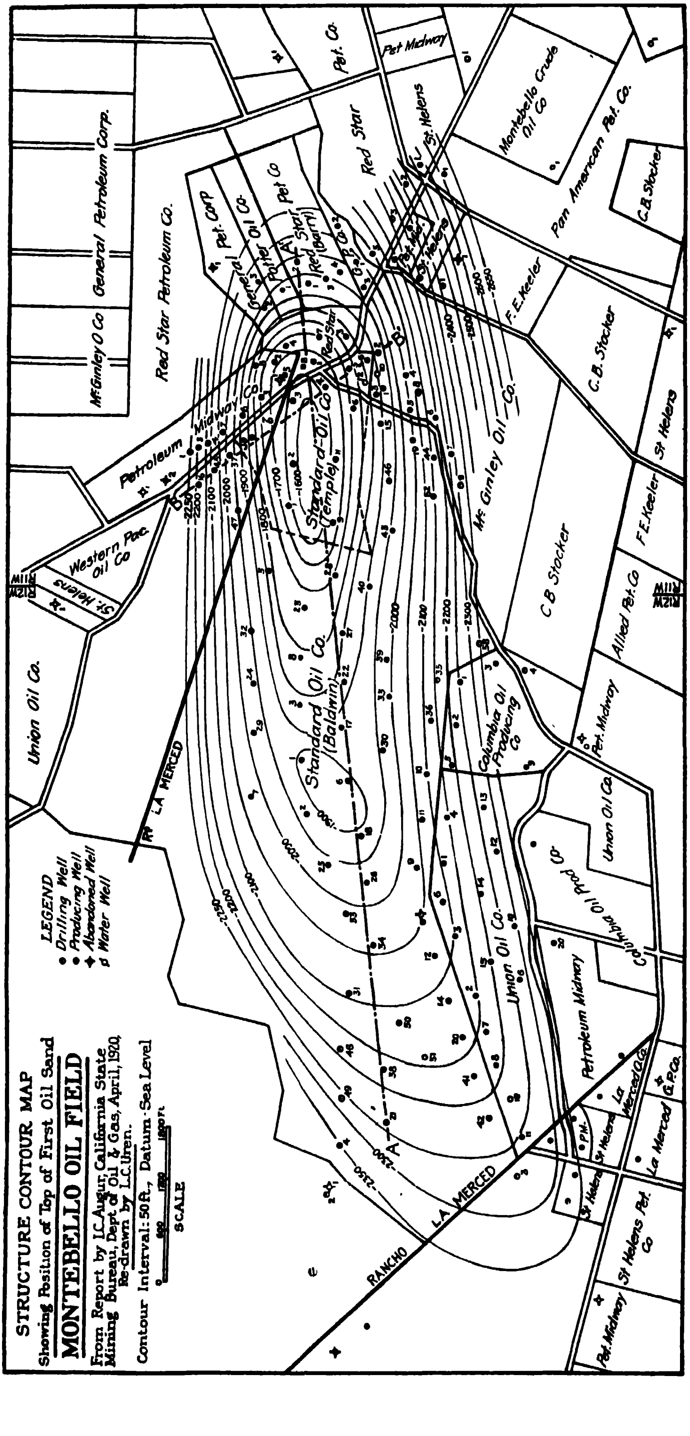
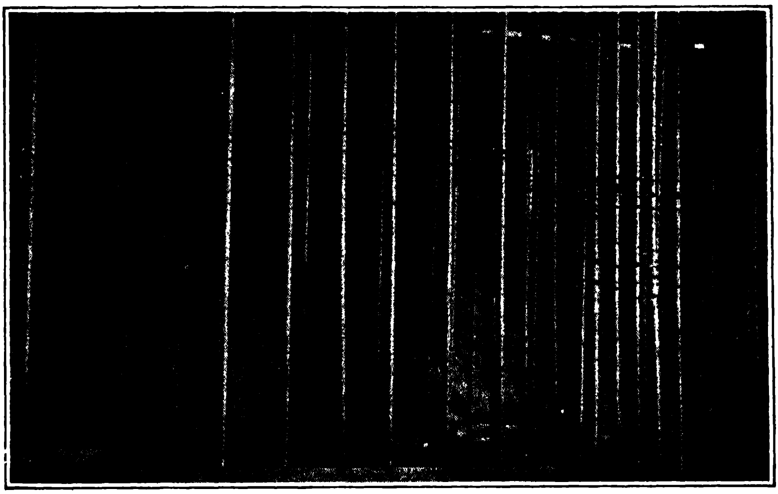


FIG. 25.—A typical structure contour map developed from well log data. Note that vertical sections along lines *A-A'* and *B-B'* are reproduced in Fig. 24.

Peg models are widely used in making correlations of structure between one well and a group of others, and are especially useful in determining the proper points at which to cement off water in a drilling well, in predicting the position of oil, gas and water sands, the proper position for casing perforations, casing depths, etc. Any marked irregularities in well depths are brought out at once by inspection of such a model.

A peg model is easily made.[3] First a baseboard of suitable size must be prepared. The baseboard should be made with mortised ends so that it will not warp, should be planed smooth on top and should be about 1½ in. thick. It is customary to cut the baseboards so that they represent, according to some assumed scale, the area of



(Courtesy of Cal. State Min. Bu., Dept. Oil and Gas).

Fig. 26.—A typical peg model.

a section or quarter-section of land. The scale used is often 100 ft. to the inch. The well locations and property lines, names of property owners, etc., are then carefully scaled off and indicated on the baseboard, developing what is in effect a rough map of the area represented.

At each well location a hole is drilled with a drill press to a uniform depth, usually about 1 in. Care must be taken in boring these holes that they are absolutely vertical, otherwise the pegs will not stand vertically above the board. The pegs used may be of seasoned pine, about ½ in. in diameter. All pegs should be of the same diameter and length. These pegs or dowels can be turned out by any planing mill at reasonable expense.

A blueprint of a graphic log, drawn on a scale of 100 ft. to the inch, is then cut just wide enough to wrap around the peg, and is glued onto the peg. The logs should be mounted on the pegs so that the sea level, or datum line, in each case lies in the same horizontal plane, or at the same distance from the lower end of the peg. To accomplish this, the pegs are marked a certain distance from the baseboard, and the sea level line, or other datum line of the log, is pasted opposite that mark. The datum plane thus established should be far enough above the baseboard to allow the deepest wells to be shown to their full depths. The pegs should be long enough to show all formations penetrated by the well with the highest surface elevation.

The pegs representing different wells are then placed in their corresponding holes in the baseboard, and the principal oil or water sands are correlated by means of bright-colored threads running from peg to peg. Usually, also, one definite marker is shown by means of a certain colored string. Push pins with colored enameled heads may be used to advantage on the pegs, to indicate water shut offs and other important features of the work (see Fig. 26).

One of the larger oil companies uses small aluminum or steel rods (¼ in.) instead of wooden pegs, and the formations are painted on the rods with the aid of a lathe.

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CHAPTER IV

DEVELOPING THE FIELD

Once the existence of an oil field has been proved by the drilling of a commercially productive well, interest at once centers on the problem of determining the extent of the field, that is, the area within which production will be obtained, and the position of the more productive sections. Knowing that a given area will be productive, the property owner within that area is then confronted with the problem of planning a development campaign with respect to definite boundary lines, which will adequately protect his property against the activity of neighboring operators, and which will result in the maximum profit being obtained from the land. The planning of the development program involves careful consideration of a number of inter-related factors, among which are the spacing and arrangement of wells and the economic rate of development as influenced by the cost of drilling, the probable future selling price of oil, the capital cost of the land and its equipment, the productivity and rate of decline of the wells, and the interest rate to be demanded on the investment.

EXPLORATION: DETERMINING THE LIMITS OF THE FIELD

The discovery well proves that oil is present in commercial amounts, and gives important information concerning the sequence and nature of strata penetrated, and the horizon in which the oil is found. The possibility of obtaining production from areas about the initial well will be a matter of conjecture until additional wells can be drilled, though if it is possible to work out the geologic structure from surface evidence and determine the direction of the major axis of the fold in which the oil has accumulated, the geologist may predict the most favorable direction from the discovery well for further development. The type of structure, the magnitude and extent of the fold and the dip of its flanks and axial line will be important considerations in determining the position of second, third and later test wells, and the distance at which they may be spaced from the discovery well. Usually the operator will be anxious to "prove" the largest possible area with the fewest number of wells, still without running the risk of locating a well beyond the limits of the pool and drilling a "dry" hole.

If the structure indicates a well-developed anticline or dome, exploration for the limits of the productive area may be conducted by drilling

wells first in both directions along the major axis of the structure, locating the wells as nearly as possible along the structural crest, and secondly, along a line at right angles to the axis, locating wells alternately on either side of the crest, thus exploring down the flanks until edge water is encountered, or until the wells become such small producers that they cease to be profitable. If the logs of these wells are carefully preserved, it should be possible, from a study of the results recorded, to gain a fair impression of the disposition of the producing oil sand or zone and perhaps even to draw a rough structure contour map of its top surface (see Fig. 27). Later drilling along other lines at right angles to the major axis may

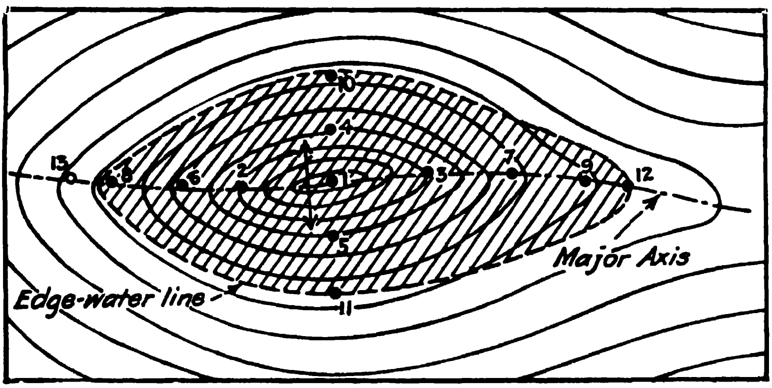


FIG. 27.—A structure contour map showing location of test wells on dome structure to determine the productive limits of a new field.
Hachuring shows productive area.

disclose local variations in dip and thickness of the oil-bearing strata, but such changes will not greatly alter the extent of the productive area as determined from the data accumulated and applied as described.

If the structure is monoclinal, it will usually be possible to locate the outcrop definitely, and by measuring its dip at various points, to determine very closely the depth to the productive stratum at any location. Usually the first test wells will be drilled near the outcrop so that the wells are shallow, and yet they should be located far enough down-dip to avoid the zone of oxidation near the outcrop. Oils near the outcrop are often heavy and viscous by reason of seepage and evaporation losses of the lighter constituents at the surface, and do not give a fair test of the capabilities of the structure. Exploration will be conducted along lines at right angles to the strike, locating wells to penetrate the producing zone at successively greater depths until the lower limits of the pool are encountered.

Factors Influencing Productivity and Form of the Field

From the foregoing it will be observed that location of wells in the development of an oil field is based primarily upon geologic considerations. While extensions of the field from a discovery well may be predicted on the evidence of structure, the form of the field and productivity of different portions of it will be largely influenced by minor changes in dip or hade of the structure and by lithological variations in the productive strata.[5]

The Influence of Dip and Hade of Structure.—A steeply dipping anticlinal formation would indicate a narrow productive area—perhaps a long narrow strip of territory along the structural crest. Plunging of the axis at either end of an anticlinal structure would definitely limit the productive area in the direction of the strike. The extent of a field located on dome structure would be greatest in the direction of the lowest dips, and relatively narrow in the direction of steep dips. A symmetrical dome with strata dipping at the same angle in all directions is rare in nature. The major structure is often influenced by intersection with minor folds. Two intersecting anticlines may result in forking of the productive area, or a local widening of the field. Wells located at such intersections also are likely to be more productive than elsewhere since anticlinal intersections cause doming, with resultant concentration from all directions instead of two. A change in the direction of strike of an anticlinal fold is regarded as favorable to local concentration and high productivity of wells, since here also the lines of oil migration up the dip are brought to a focus, particularly on the convex side of the fold. Though local variations of this character are of importance in selecting the more valuable areas within a field, it must be recognized that the extent and continuity of the field as a whole is dependent on persistence of structure and maintenance of an approximately level axis.[6]

The Influence of Lithological and Stratigraphical Variation.—The shape of the field and the productivity of areas within it will be greatly influenced by changes in the porosity and thickness of the oil-bearing strata. Variation in porosity, if extreme, will result in highly productive lenticular pools surrounded by almost barren areas, though the major concentration may have been effected by a well-defined anticlinal structure embracing both the productive and non-productive areas. The more porous rocks will naturally give the higher initial yields, and wells drilled into thick oil sands will be more productive than those deriving their oil from thinner strata. Local variation in the thickness of an oil-producing stratum will thus cause great irregularity in property values. Local "pinching out" of a productive sand may result in an area within the heart of a producing field being practically barren.

The extent of the field and the productivity of different portions will also be influenced by the number of oil-bearing strata occurring beneath it. It often happens that there will be several well-defined oil sands, perhaps separated from each other by several hundred feet or more. In such cases the lower strata are often less influenced by the structure; that is, they dip at lower angles, and the productive area will be wider. Productive lower zone wells may thus penetrate the upper zone beyond its productive limits. Then too, if the fold is asymmetric, the axis of a lower sand will not conform with that of an upper sand, so that the more productive first-zone wells may be less advantageously located with respect to the lower zone (see Fig. 2).

Correlation of Well Log Data.—Even though competent geologic advice is to be had, the early period of development in a new field will often be one of great uncertainty. Perhaps a number of operators will be in competition with each other for early production, and efforts are chiefly directed toward speed in drilling rather than to the important work of securing accurate well log data to aid in correlating and interpreting structural conditions. Many operators consider their well logs as confidential information, so that it becomes a difficult matter for one interested in working out the structural and stratigraphic relationships to secure the necessary data. It is to the mutual advantage of all operators in the field that all available subsurface information be freely exchanged in order that the structural and stratigraphic features may be worked out at the earliest possible time.

Operators in a new field should make an effort to reach a common understanding on the names and characteristics of the more important strata penetrated by the wells, so that there will be some degree of uniformity in the well log data accumulated. If there are any persistent strata of striking characteristics that might serve as "marker" horizons for correlation and reference, these should receive particular attention.

If the well log data are accurate, a peg model will display the general trend of the structure as soon as a few wells have been completed; and as more pegs are added, the local dips and irregularities will become apparent. Often local irregularities in depth to production, or dry holes drilled in locations thought to be productive, will cause confusion during the early period of development; and if there are several oil sands within a productive "zone," as is often the case, variations in the productive area covered by the different sands may further complicate the problem. Often the position of "water" sands will be uncertain, and irregularities in the position of "water shutoffs" and landing depths for casings in near-by wells will allow water to enter the oil sands at certain points, to the detriment of oil production. Obviously, accurate well logs should be the primary consideration during the early period of development, in

order that these irregularities may be fully understood and a uniform system of casing wells and excluding water worked out.

If the ordinary rock characteristics are not sufficiently distinctive to furnish a means of correlating strata from well to well, a closer study of formation samples from a few wells that have been carefully drilled and systematically sampled will usually disclose certain peculiarities that characterize one or more of the persistent strata.[2] A particular sand may contain an unusual percentage of some distinctively colored or crystallized mineral, such as hornblende or biotite or olivine; or the sand grains may be unusually coarse or fine or even-textured. Another may contain a particular type of foraminifera or other fossil indicator. The water contained within a water sand may have unusual chemical properties. Often, if there is more than one oil sand, the oil will differ somewhat in gravity in the different strata. Some of these are properties which will require skilled technical assistance in identification, but if such a relationship is once established it will serve as a useful means of correlation, perhaps throughout the entire field. Local irregularities or erroneous log data may by such means be readily adjusted to the established markers and stratigraphic correlation completely established.

PLANNING THE DEVELOPMENT PROGRAM

Unfortunately for the average operator, he is seldom in control of the entire area within a producing structure. Ordinarily several, or perhaps many, independent operators will own different portions of the field and will enter into competition with each other for production. All produce from what is, in effect, a common reservoir, and the activities of one operator will directly influence the ultimate recovery to be effected from neighboring properties. Location of the early wells in undeveloped territory will therefore be influenced by property lines as well as by geologic structure and local lithological variations; indeed, protection of property lines is often given the greater consideration.

Influence of Neighboring Development on the Development Program.—With the idea of preventing drainage across property lines, it is customary to drill the "outside locations" along boundaries, before the interior locations are drilled. Often the first wells on a property will be placed in the corner locations, thus protecting against drainage by corner wells in the three adjoining properties. The side boundary wells will next receive attention, no interior locations being drilled until all of the line wells have been completed.

This program assumes that all surrounding operators are equally active. If all neighboring activity should be concentrated on one side of a lease, the boundary wells on that side would be first drilled, and perhaps one or two rows of interior wells will also be drilled on that side of the

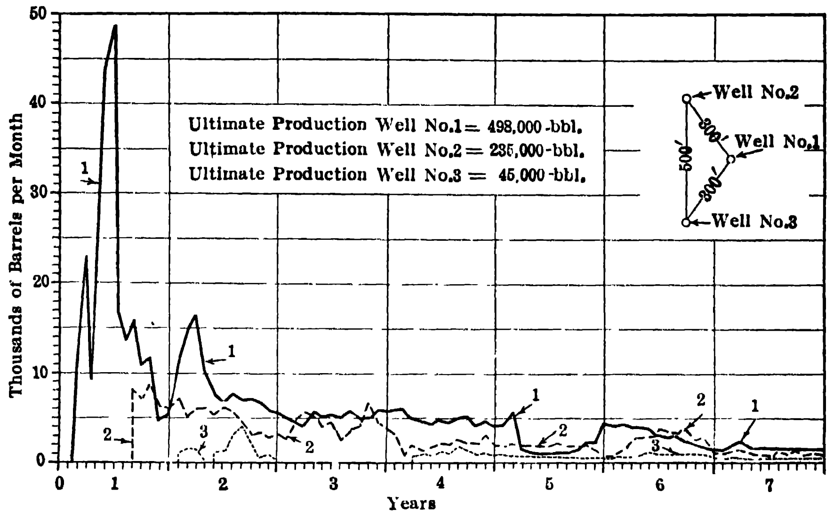
property before attention is given to the other wells along boundaries where competition is not keen. If a property is located on the edge of a producing field, it may be that production on the side nearest the field will be practically certain, while the possibility of obtaining oil in wells drilled along the far side (usually the down-dip side) will be more or less problematical. In such a case, in order to avoid the loss occasioned by the drilling of dry holes, development may proceed progressively down-dip from the boundary nearest neighboring producing wells, the down-dip boundary locations not being drilled until it is fairly certain that they will be profitable producers.

The planning of a development campaign with respect to neighboring activities has both defensive and offensive aspects. The operator who first brings his property to full development will secure more of his neighbors' oil than they are able to secure of his. Closely spaced wells and wells of large diameter will drain an area more rapidly and thoroughly than a fewer number of small wells. Then too, the early wells in an undeveloped area will usually have the greater ultimate productions. Initial productions are higher because of greater gas pressure during the early stages of development, and the earlier wells seem to maintain their superiority in later years, possibly by establishing drainage channels during the early period before interference by later drilled wells becomes a factor of importance.

The advantages of securing early production are fully recognized by most operators. When the gas pressure is high, the initial and ultimate productions of wells will be greatly in excess of those obtained from wells drilled a few years later when the field pressure has declined. Failure to drill wells within a suitable time (in terms of the rate of surrounding development) will often mean a loss of considerable magnitude when the present value of the ultimate production of a property is calculated. Figure 28 illustrates a typical case in which wells were drilled within a short distance of each other, apparently in equally advantageous locations. Well No. 1, however, was drilled 7 months before No. 2, and No. 3, 5 months later than No. 2. Well No. 1 will ultimately produce 2.12 times as much oil as No. 2, and more than 11 times as much as No. 3.

Offsetting and Line Agreements.—As a measure of protection against drainage across property lines, it has become customary for adjoining property owners to place their line wells directly opposite each other (*i.e.*, on a line at right angles to the boundary line) and at an equal distance from the boundary line, a practice known as "offsetting." If A drills 8 wells spaced 660 ft. apart and 100 ft. back from the line along his west boundary, operator B, owning land on this side, must drill as many wells similarly spaced along his east boundary, otherwise A gains the advantage in production from the line wells. This advantage can actually be translated into terms of equivalent acreage.[5] The obvious dis-

advantage to all parties concerned, of adjoining operators entering into "boundary warfare" through competition in the drilling of line wells, has led in many instances to formal agreements not to drill more than a stated number of wells along the common boundary, and to drill not closer than a specified distance from it. Such regulations are sometimes tacitly accepted by all the operators of a field or district, so that the spacing of wells along boundaries is approximately uniform throughout



(*After J. H. G. Wolf*).

FIG. 28.—Production graphs of three contiguous wells in the Midway field, California, illustrating advantage of securing early production in an undrilled area.

the field. For example, in the California fields, wells are commonly placed either 100 or 150 ft. back from the line. Spacing along the line will vary in different localities with the prevailing opinion concerning the number of wells necessary to drain the land completely within a reasonable space of time. While defensive considerations would dictate the drilling of offset wells along boundary lines directly opposite each other, less interference results when locations on opposite sides of the line are staggered. This, too, might be accomplished by mutual agreement.

Well Spacing.—The economic spacing of wells to produce a maximum return on invested capital is a variable that can seldom be precisely determined because of the large number of factors that enter, and the difficulty of evaluating them at the time that the development program is formulated. For any set of conditions there must always be a definite number of wells which will exploit a given area most profitably. There is a nice balance that exists between the number of wells, their cost, the volume and value of their ultimate production, and the productive life period, which makes it possible to calculate just how many wells we should

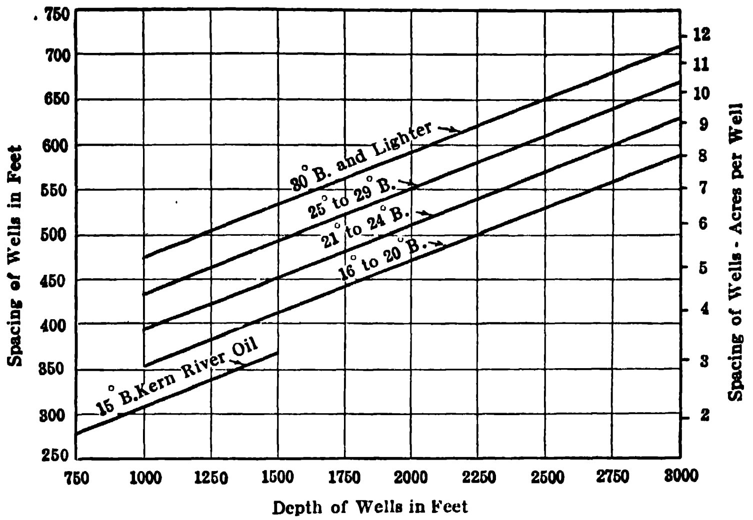
drill in a given area to realize a maximum return on our investment. Fewer wells than this economic number will often result in a lower ultimate production, with correspondingly lower percentage recovery. In some cases, fewer than the economic number of wells may eventually produce as much oil, with as high a percentage of ultimate recovery, as would the economic number, but production would be extended over a longer period and the present value of our investment would be much reduced. Drilling more than the economic number of wells would not produce any more oil in the long run, and while extraction might be accomplished in a shorter period, the increase in present value of the investment, due to a shorter period of realization, would not offset the increased development costs incurred in drilling the additional wells. Spacing is not so much a problem of determining how many acres a well will drain as it is a problem of obtaining the greatest possible production, in the minimum time, and at minimum expense.[2]

The area drained by an oil well is a variable which depends upon a number of different factors.[1] Important among these are the porosity of the reservoir rock, the viscosity of the oil and its density, the gas pressure, the diameter of the well and the method of pumping. A thick oil stratum will support a larger number of wells than a thin one. A given area of very porous sands can be effectively and economically drained with fewer wells than a like area of closer grained rocks. If very deep wells are necessary, if the cost of production is high or if oil prices are low, the economic spacing of wells will be greater than in the case of shallow territory producing high-priced oil that can be cheaply pumped.

In practice, the distance apart at which wells must be drilled in order that their productions are not mutually influenced, is found to range from about 100 ft. in close-grained rocks with heavy viscous oil and low gas pressure, to perhaps 600 or even 700 ft. in very porous formations with light-gravity oils. In the Southwest, 660 ft. is a common interval between wells, a spacing which allows just 10 acres for each well to draw upon. Other common intervals are 300, 440 and 500 ft. In some fully developed areas in the California fields,[6] the area drained by each well averages about 3 acres, but acreages of 5, 8, 10 or even higher for each well are characteristic of less fully developed fields (see Fig. 29).

Arrangement of Wells.—Some geometric pattern is usually followed in the location of interior wells, arranging them in rows across the property and spacing them equally apart so that all sections are equitably drained. A rectangular arrangement is often followed, but a triangular pattern in which the wells in alternate rows are staggered gives more complete drainage[4] (see Fig. 30). There is some justification for spacing the wells nearer together in the direction of the strike of the formation than in the direction of its dip. If it be assumed that the movement of oil is primarily up the dip of the structure, the operator should strive to

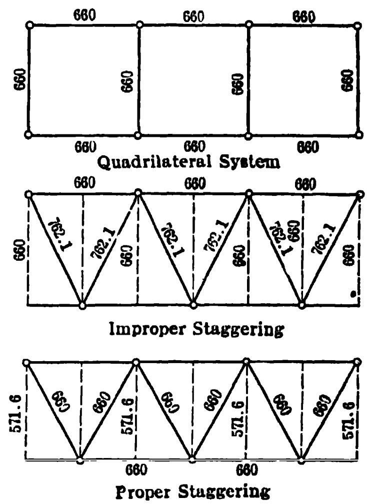
place a screen of closely spaced wells across the direction of flow; while in the direction of dip they need not be so closely spaced. Theoretically,



(*After M. L. Requa*).

FIG. 29.—Graphs showing economic spacing of wells for varying depths and gravities of oil, California San Joaquin Valley fields, 1915.

a single row of closely spaced wells along the crest of a level anticline will completely drain it, the oil migrating under the influence of hydrostatic pressure directly up the dip of the structure. However, if the flow be considered as due chiefly to gas pressure, which is equal in all directions, the dip of the formation will have little significance. If we assume that drainage is due entirely to gas pressure, in steeply dipping strata the wells should be logically placed nearer together in the direction of dip than in the direction of strike. This follows from the fact that the well intersections with the producing sand are further apart as measured in the plane of the dip than they would be with reference to a horizontal plane.



(*After R. H Johnson, in Trans. Am. Inst. Mining and Metal. Engrs.*).

FIG. 30.—Illustrating rectangular and triangular systems of well spacing.

Often the spacing and arrangement of the boundary wells will determine the position of interior wells, particularly if the property is a small one. There is better opportunity for scientific well spacing and arrange-

ment when land is held in large tracts than when small acreages are the rule. Town lot drilling in some of our western American fields, with resultant overcrowding of wells and unequal spacing, has resulted in great economic waste, and in many cases, due to overdrilling and mutual interference, operations have been unprofitable.[2]

Rate and Order of Drilling.—It is apparent that if we hurriedly bring an oil property to full development, we will have a rapidly increasing

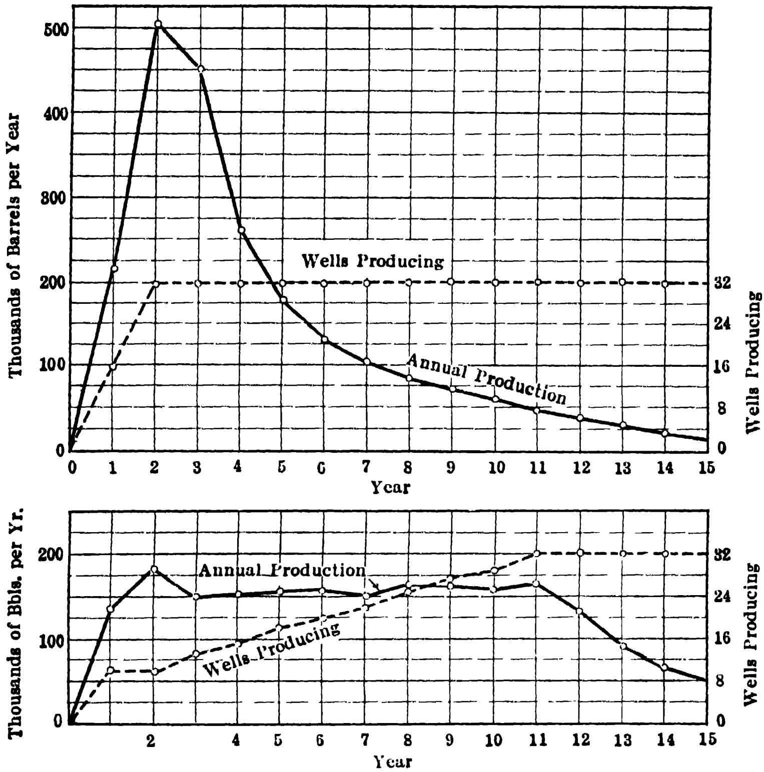


FIG. 31.—Estimated production of an oil property with rapid development (upper graphs), and with slow development planned to maintain uniform output (lower graphs).

Note that in each case wells are assumed to be so spaced that they have equivalent initial productions and decline rates

daily production, which reaches a peak rather early in the life of the property and then gradually declines as the productivity of the wells decreases, until, during the latter years of the productive life of the property, the daily production reaches a comparatively low figure (see upper graphs, Fig. 31). This plan of development probably results in the greatest ultimate production, but it has the disadvantage that the drilling, production, storage and transportation facilities are greatly overtaxed during the early years, usually necessitating the equipment of the property on a scale far in excess of what is required during the

later years. Furthermore, when this plan of development is followed there is some possibility, in restricted markets, of overproduction during the early period, which reacts to depress prices; so that the gross returns will be somewhat reduced by a lower average selling price per barrel.

While the maximum amount of oil is secured by drilling all of the wells at once, such a program is often impracticable, since the drilling of a large tract must necessarily extend over a number of years. The physical difficulties of road building, rig construction, securing and distributing water supply, camp construction, etc., must precede drilling. The cost of duplication of well-drilling equipment necessary for an intensive drilling program, and the provision of working capital for the drilling of many wells at the outset of operations, is often prohibitive. The producer usually finds it expedient to finance a part of the cost of developing the property from its production; hence a few wells are drilled first, placed on production and new wells added as rapidly as finances and working conditions permit.

Most operators prefer to bring the production rapidly up to a predetermined daily production which will provide a suitable return on the investment, and then discontinue further drilling until such time as the wells begin to decline. Thereafter, new wells will be drilled at a rate just sufficient to maintain the production at the desired level (see lower graphs, Fig. 31). This plan results in a uniform rate of production throughout the greater part of the life of the property, and the disadvantages of an intensive preliminary development campaign are largely eliminated.

The development of an oil property may be conducted according to either of several plans.[3] A common method is that of drilling rows of wells, blanket fashion, across the property from proved territory to unproved territory. This plan gives maximum insurance against the drilling of dry holes when it is not certain that the entire area beneath the property is productive. It also offers opportunity for securing necessary information on structural and subsurface conditions for new locations, before drilling is begun. That is, geologic surmise based on data from wells only one row distant, is relatively certain in comparison with estimates projected to remote locations in untested territory. A somewhat similar plan is that of drilling progressively outward from productive test wells as centers.

Another method of development involves the preliminary drilling of widely scattered wells at some uniform spacing (say 15 to 30 acres per well); then, after this primary system of wells has been completed, intermediate wells are drilled at a smaller interval calculated to give the most economic extraction. This plan has three distinct advantages: The initial productions of scattered wells are, as a rule, considerably higher than those attained by the usual spacing; production from widely spaced wells is better sustained than that from wells closely spaced; and final

decision as to the ultimate spacing and disposition of wells can be deferred until fairly complete information is available on which to base computations of economic spacing. As is shown in Chap. XIII, however, the secondary system of intermediate wells will be deprived of the higher gas pressures and will be relatively small producers, due to deferment of the period of drilling and interference from the primary wells. The ultimate production per acre is therefore lower when this plan is followed. It is evident, however, that early wells in isolated positions, having relatively high initial productions, and following with several years of sustained production, will during these years yield to the producer greater and quicker returns than would the same number of closely spaced wells which are as expensive to drill, yet have a lower average yearly production. The loss in ultimate recovery of oil may therefore be compensated by the earlier return on the investment, elimination of the possibility of drilling too closely and a better final spacing of the wells based on production data from the primary wells.

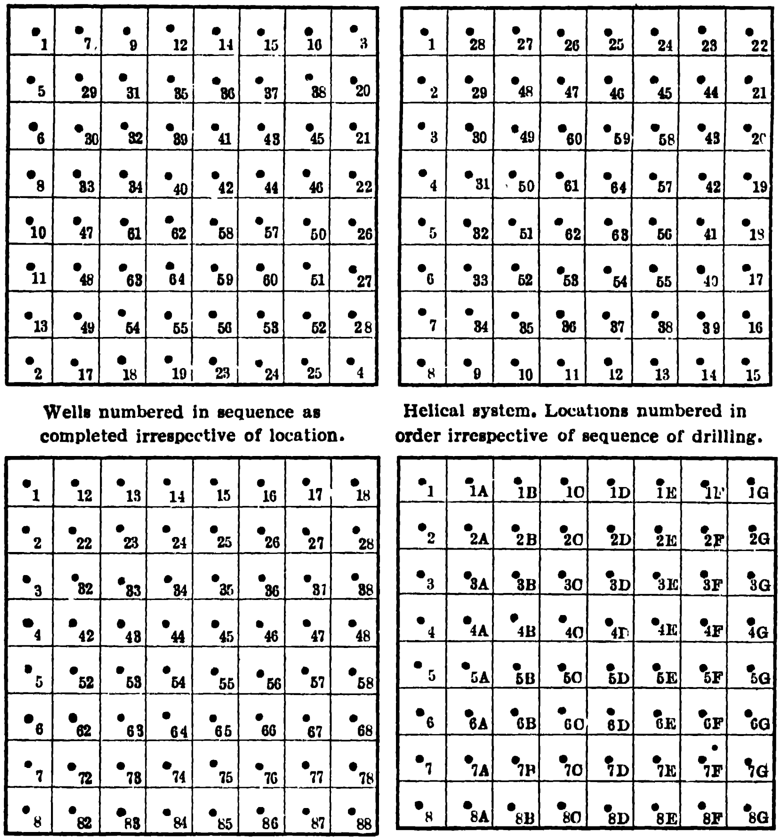
Examples illustrating the greater productivity of widely spaced, isolated wells may be found in every oil field, but the following data given by Cutler[3] are representative:

> During the 5-yr. period, 1913 to 1917, the average yearly initial production of 24 isolated wells in the Buena Vista Hills area, California, was 260,000 bbl., while during the same period, that of 104 offset wells was 172,000 bbl. per year; that is, the initial productions were 50 per cent greater for isolated wells than for closely spaced wells. If we assume a drilling campaign which would permit isolated wells to produce 3 years before being offset, the average isolated well, having an initial yearly production of 260,000 bbl., will produce 567,000 bbl. according to actual production records. During the same 3-yr. period, the average offset well with an initial yearly production of 172,000 bbl. will produce only 345,000 bbl., showing a gain for the isolated well of 222,000 bbl. This indicates the gain in immediate recovery due to isolation in the Buena Vista Hills area.

The production decline of widely spaced wells is accelerated when their drainage areas are encroached upon by interspaced wells. Hence, the benefit to be derived by drilling scattered wells is negligible if it is followed by rapid drilling of interspaced wells.

Numbering of Wells.—It is customary to number the wells on each property for convenience in reference, in the order in which they are drilled (see Fig. 32). An alternative plan, one followed by some of the larger oil companies operating many different properties, is to number the wells with reference to their position and irrespective of the order of drilling. One becoming familiar with such a system knows at once, from the well number, its position on the property, but the well numbers would not indicate their relative ages.

Economics of Oil Field Development.—The economic life of an oil property is that period of time within which, if all available oil is extracted, a maximum profit will be realized. The estimation of this economic period of productivity is one which confronts every oil operator in planning his development program and determining the maximum rate



Wells numbered in sequence as completed irrespective of location.

Helical system. Locations numbered in order irrespective of sequence of drilling.

Coördinate system. Locations numbered in order irrespective of sequence of drilling.

Coördinate system using figures and letters.

FIG. 32.—Systems of numbering oil wells.

of productivity which he should try to attain. A variety of factors must be considered, including the productivity of the wells and their rate of decline, the estimated future selling price of oil and the cost of production, the capital cost of land and equipment, and the interest rate on invested capital.

It is obvious that the oil will be exhausted more rapidly from a given tract by drilling a large number of wells than if drainage is dependent

upon a smaller number. The bulk of the production is obtained relatively early, and the wells show a rapid decline rate. The present value of this early production will be greater by reason of the shorter period of realization and the consequent saving in interest charges, but the increase in value will be tempered by the capital cost of the larger number of wells. Furthermore, the cost of operating a large group of wells may be greater than for a small group, even though the period of operation is shorter. Theoretically, the same considerations would warrant drilling the requisite number of wells to bring the property to full development as early as possible. Anticipated increase in the future selling price of oil may entirely alter the result in either case, perhaps warranting slow development and deferment of realization on the bulk of the production.

The cost of production as an element in determining profits must not be forgotten. Anticipated increases in the cost of production may in future years greatly reduce the margin of profit which we discount to determine present value. The rate of interest expected on invested capital will greatly influence the present-day values, and will have an important bearing in determining the economic number of wells to be drilled. The shape of the property and the activity of neighboring operators must also be considered in formulating the development program. Active development on surrounding properties may mean the definite loss of a considerable volume of oil unless an equivalent pace is maintained, a consideration which may offset other factors opposing early and rapid development. A long narrow strip of property demands more rapid development than a square compact area, because of the advantages gained in increased production from neighboring land, and the difficulty of adequately protecting a lease of such shape from outside drainage.

To all of these factors the operator must give due consideration in calculating present values of apparent profits; and computations must be made for several different assumptions of the number of wells and time or rate of drilling them. The combination of variables indicating the maximum apparent profit will, of course, be adopted.

Development of Surface Plant and Equipment.—The drilling of wells constitutes only one phase of the general problem of oil field development. In addition, the operator must give attention to the building of roads to facilitate transportation of materials and equipment; power and water development and distribution must also be considered. The provision of a gathering and storage system is essential; and the erection of buildings to house shops, reserve supplies, power plant, office staff and equipment, sleeping and dining facilities for the employees, living accommodations for their families and other camp necessities will be important considerations in the early development period (see Chap. XVII).

Transportation of supplies and equipment will necessarily receive early consideration, for timber, rig irons and parts, drilling equipment and casing must be hauled to the sites selected for the wells. Ordinarily, motor trucks will be used in transporting supplies and equipment, so the roads constructed must be capable of withstanding heavy loads, and the grades should not be excessive. Routes should be selected which will give convenient access to all parts of the property.

Unless the property is near a town where ordinary living accommodations are available for employees, camp facilities must be provided in advance of other development work. Such facilities may not at once be developed to the same degree as may be necessary or desirable during later years, but the initial effort in this direction must be adequate to provide the necessary camp conveniences. Machine and forge shops adequately equipped to care for such repair work and tool dressing as will be necessary, must be provided in advance of much development work; and a warehouse and office building to house the clerical and technical staffs must be built. These facilities may be of rough temporary construction, with the expectation of replacing or improving them later if results of development warrant it, but if it is certain that the property will be productive over a considerable period of years, it will be more economical to build at the outset for the estimated productive life of the property.

The provision of power will be an important matter. This requires, first of all, selection of the form of power, which may be either steam, electric or gas power. If steam power is determined upon, it will be important to develop a source of water suitable for boiler purposes. This may necessitate the drilling of a water well, or the construction of a dam, or it may be necessary to buy water from outside sources. Distribution of water over the property will require a piping system adequate not only for boiler purposes, but to provide water for drilling purposes as well. The erection of boiler plants with all incidental and related equipment at various points about the property, or of a larger central plant, will require careful designing if reasonable efficiency is to be secured. Distribution of steam from power plants to the points of use will require a system of steam mains. Electric power necessitates the installation of poles, wiring and transformers in addition to the steam plant, unless power is purchased from outside sources. These matters are discussed in greater detail in Chap. XIV.

As soon as the first well is completed and placed on production, it will be necessary to provide oil storage sumps, reservoirs or tanks, and gathering facilities for both oil and gas. This part of the surface equipment will ordinarily be developed gradually to keep pace with the productivity of the wells as completed, but its layout and design should be carefully planned in advance with reference to the shape and size of the

property and the topography (see Chap. XV). Gas traps of suitable capacity and design must be provided to separate occluded gas from the oil. Dehydrating equipment, often a very essential part of the surface plant in the declining years of the property, is not ordinarily necessary during the early development period.

In addition to the foregoing essential features of the surface plant, many other details must receive consideration: an electric lighting system is desirable; telephonic communication with various parts of the property will be a great convenience; fire protection is important. An absorption or compression plant to strip gasoline from natural gas, or a small topping plant is often an incidental part of the oil lease equipment.

The equipment of the property belongs distinctly to the development period. While the surface plant must be developed more or less gradually, the property cannot be expected to operate at maximum efficiency until the surface equipment is complete, and every element of it is properly coordinated. Both the cost of the plant and the cost of development represent capital outlay that will be productive over the greater part of the life of the property, and as such they are of equal significance in planning for its development.

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CHAPTER V

CHURN DRILLING METHODS

The methods used in drilling oil wells may be classified into two main groups, in each of which there is one well-known and widely used method, and in addition, a number of relatively unimportant and comparatively little-used methods. These two groups we may call: (1) churn drilling methods, and (2) rotary methods. The present chapter will be concerned with churn drilling methods, while Chap. VI will be devoted to a description of rotary methods.

Classification of Churn Drilling Methods.—Methods which accomplish excavation of the well by the reciprocating or up-and-down churning action of a drill may be classified as follows:

1. Hand drilling methods: spring pole rigs
2. Cable drilling methods:
   (*a*) The American "standard" rig
   (*b*) Portable cable tool rigs
3. Rod and pole drilling methods:
   (*a*) The Canadian pole tool rig
   (*b*) The Galician rod tool rig
   (*c*) Free-fall rigs

Of these various methods, only one—the "standard" cable system—is important in American oil well drilling practice. The others are used to some extent in drilling oil wells in other parts of the world, and in drilling wells for other purposes. The present chapter will be entirely devoted to the cable system of drilling because of its greater importance from the point of view of the American oil producer. The reader is referred to the bibliography given at the close of the chapter for descriptions of the rod and free-fall systems which are chiefly used in the Russian, Roumanian and Galician fields (see particularly references 9, 11, 13 and 16 at end of chapter).

General Requirements of a Drilling Method.—Any successful system of drilling oil wells must provide first of all a means of fracturing or abrading the rocky formations which must be penetrated to reach the oil reservoir; and secondly, it must provide a means of excavating the loosened material from the well as drilling proceeds. In addition, provision must be made for preventing the walls of the well from caving, and for sealing off water and gas. Wells must usually be vertical or

nearly so. The well must, of course, be deep enough to reach the oil reservoir, and it must be of adequate cross-section to permit of the introduction and operation of a pumping device of sufficient capacity to make operation of the well profitable.

Oil wells vary in diameter within wide limits. Prospect wells, drilled primarily for information rather than for production, may be finished with a diameter as small as 2 or 3 in. Wells in the Russian and Roumanian fields are occasionally drilled with initial diameters as great as 36 in. It is usually necessary to decrease the diameter of a well progressively as the depth increases, in order to provide adequate clearance for the drilling tools and to permit of the introduction of metal casings for retaining the walls and excluding water. In American practice, initial diameters commonly range from 11 to 21 in., depending upon the depth to be attained, the number of reductions in diameter necessary and the size with which it is considered desirable to finish the well. This latter factor depends, in turn, upon the productivity of the territory. For American practice, finishing diameters range from 3 to 7 in., most operators preferring a free working diameter of at least 4 or 5 in. The 2-in. plunger pump, which is the smallest size ordinarily used, requires a free working space at least 3 in. in diameter. The 3-in. plunger pump, which is the most commonly used size, requires a free working diameter of about 4½ in. The 4-in. pump, the largest commonly used size, requires a free working diameter of about 5½ in.

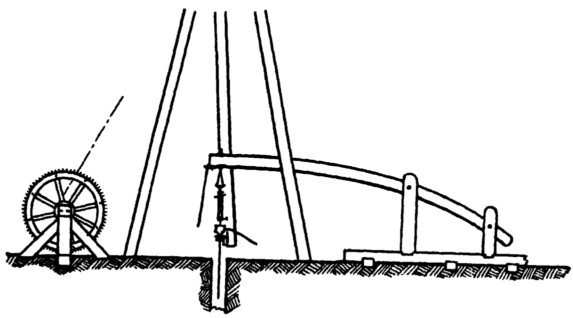
The maximum depth to which it would be practical to drill a well with modern equipment and methods, would depend somewhat upon the character of the formations to be penetrated, the size and weight of the equipment used, the power available and the skill of the driller. Wells have been drilled with churn drilling cable tools to depths in excess of 7,300 ft., and with rotary tools to more than 7,000 ft. The deepest well yet drilled, near Fairmont, W. Va., was drilled with cable tools to a depth of 7,579 ft. There seems to be no good reason why drilling equipment of either type could not be designed to drill to greater depths if necessary.

The depth to which it is profitable to drill is the determining factor in most drilling operations. This economic limit of depth varies with the quality of the oil, the prevailing selling price, the productivity of the well, the cost of drilling and other factors. Such factors are quite variable. Within recent years, wells drilled to depths in excess of 4,000 ft. for a production of 100 bbl. per day of 25°Bé. oil, have been found profitable in some localities.

THE AMERICAN STANDARD CABLE SYSTEM OF DRILLING

Development of the American Standard Cable System.—The origin of the cable system of drilling is uncertain, but historical references

show that it had reached a fair state of development in China prior to the seventeenth century. It is said that up to the year 1700, the Chinese had sunk over 10,000 wells to depths of over 500 m. for the production of brine. Practically all of the equipment used in drilling these early wells—rope, pipe and derrick—was made of wood, the elastic bamboo being widely used. The power used was man power. The drilling tools were suspended from the end of a spring pole, the churning movement being given to the tools by the workmen running up a short incline and jumping down one after another, on a small platform also attached to the spring pole.[17]



(*After R. B. Woodworth in Trans. Am. Inst. Mining Engrs.*)
FIG. 33.—Spring-pole rig for cable drilling.

The spring pole method, with minor variations in the manner of applying the power, was also widely used in other parts of the world in drilling wells for various purposes, chiefly for brine. The records of well drilling in the United States begin in 1806, when the first American well was drilled near Charleston, W. Va., for brine. The appliances used in drilling this first American well were very simple.[17] A spring pole 20 ft. long was mounted on a forked stick of wood and fastened to the ground at one end (see Fig. 33). Attached to the free end of this spring pole, was the drilling cable, to the lower end of which the iron bit, 2½ in. in diameter and quite primitive in construction, was fastened. Stirrups, also attached to the free end of the pole, were used by two or three men in producing the necessary churning motion, their weight pulling the cable down, while the elasticity of the pole served to jerk it back with sufficient force to raise the tools a few inches. The casing consisted of two long strips of wood, whittled into half tubes and wrapped with twine. The conductor was a straight, well-formed, hollow sycamore gum, 4 in. in internal diameter, sunk to bed rock in a shallow pit. Even in this primitive equipment, used on our first American well, all of the essential features of what we now call the "standard" cable system of drilling, were present. We still use the same method of drilling, but our equipment is more elaborate.

The first well drilled for oil in the United States was the Drake well, sunk near Titusville, Pa., in 1859. Many of the shallow wells that were drilled in the same locality following the discovery of oil in the Drake well were drilled with the aid of spring poles by hand methods. As might be expected, the early operators of these laborious and slow hand drilling rigs soon began to contrive mechanical means for applying the power. The steam engine was the best known prime mover in the early days, and naturally the first mechanically driven drilling rigs were operated by steam engines. The engines used were of the simplest type: an ordinary reversible engine, with the piston controlled by a plain slide valve—a type of engine which in spite of its inefficiency is widely used even today for the drilling of oil wells. The engine was used to give a reciprocating motion to the drilling cable through the instrumentality of a large wheel, called a "band wheel," the metal shaft of which was connected to one end of a walking beam by means of a crank and pittman. The drilling cable attached to the opposite end of the walking beam was thus given a churning motion with each revolution of the band wheel.

The first rigs were light and small, for the wells were shallow and the duty not severe. For hoisting out the tools, a simple tripod was used, made of three sticks of timber tied together at the top and supporting a crude wooden or iron pulley. The drilling cable was passed over the pulley and power applied to the free end by a hand power windlass or a mechanically operated hoisting drum. Such drilling rigs served well enough in the shallow territories which were first exploited for oil, but were soon found to be inadequate when deeper drilling became necessary, or when more difficult conditions were encountered. Small changes were made here, an improvement there. New parts were added as new duties were imposed, until finally there was evolved the modern cable drilling rig which we call the "American standard rig."

The American Standard Cable Rig

Sixty years of development, during which hundreds of thousands of wells have been drilled by this method, have now fairly well standardized the equipment used. However, there is some variation in the size and weight of the parts of the rig to adapt it to the conditions imposed in different fields. Deeper drilling, characteristic of the western American fields, has also been responsible for the addition of certain new parts, particularly for the handling of heavy strings of casing.

The standard cable drilling rig is housed and supported by a structure which has two principal parts: first, the derrick, a high pyramidal framed structure, erected directly over the site selected for the well; and second, a long narrow and comparatively low structure which houses the engine or motor, the belt, a large band wheel and other mechanism

provided for applying and controlling the power. These structures rest on suitable foundations of heavy timber, which together with certain other supports for the wheels and other moving parts, are known as the

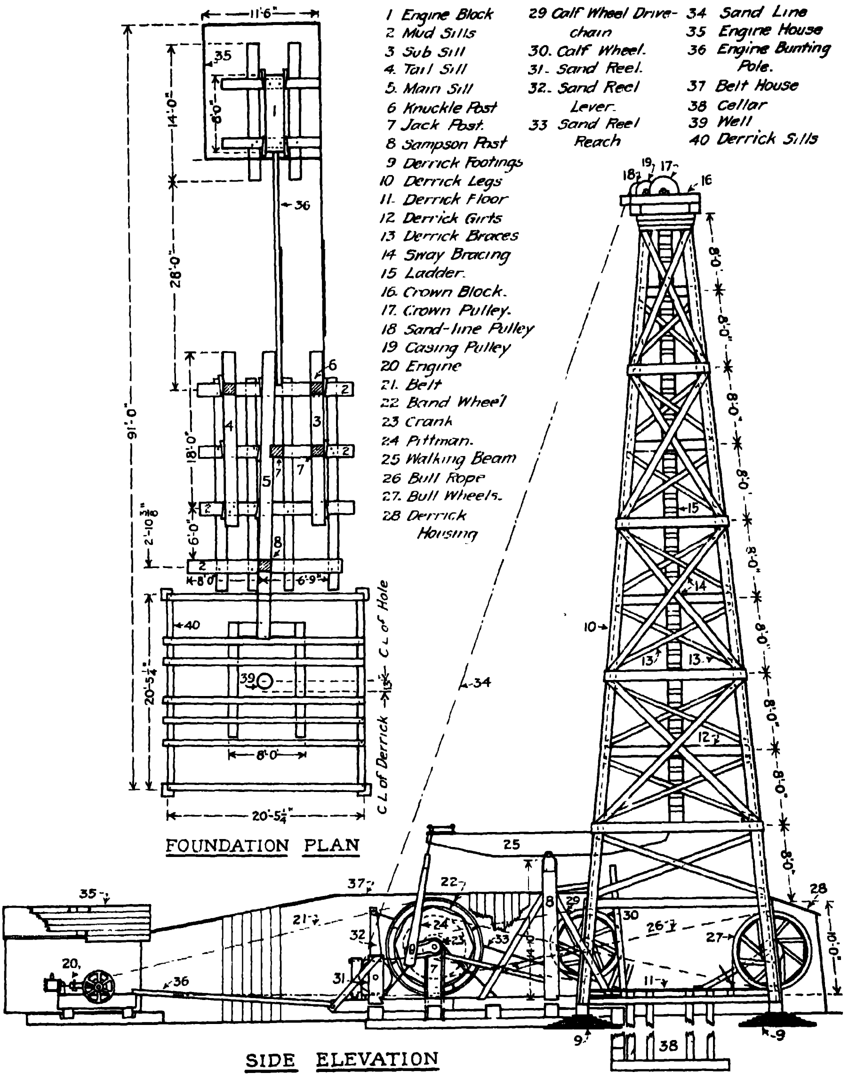


FIG. 34.—Plan and elevation of an 82-foot standard cable rig.

"rig timbers." Substantial flooring is provided under the derrick and within the engine house and belt house, and a platform is built at one side of the belt house on the same level as the derrick and engine house flooring, and connecting the two (see Fig. 34).

Motive power is transferred from the engine pulley to a large wooden band wheel by means of a belt. The band wheel is mounted, by means of metal gudgeons, on a steel shaft resting in metal bearings supported on two substantial "jack posts." Overhanging the bearing on one end of the band wheel shaft, a crank is keyed; this may be connected by means of a metal "wrist-pin" to the lower end of a pittman, the upper end of which is attached by a metal stirrup to the end of a "walking beam." The walking beam is a long substantial timber, supported at its center on a pivot and bearing, which permits it to oscillate as the crank revolves. The end of the beam opposite that to which the pittman is attached, overhangs the well, and the drilling cable on which the drilling bit is suspended may be attached to the beam with an adjustable "temper screw." By means of this simple mechanism the bit is raised and lowered an amount governed by the "swing" of the walking beam, with each revolution of the band wheel. The movement of the beam is adjustable by changing the position of the wristpin in the crank. Five holes are provided in the crank for this purpose, each at a different distance from the center of rotation of the bandwheel shaft. The movement at the end of the beam ranges from 2 to 5 ft., each successive hole in the crank adding 6 in. to the sweep of the beam.

On the side of the band wheel a wooden tug pulley is mounted, which provides a means of operating an endless rope drive (the "bull rope") to a large pair of wheels called "bull wheels." These wheels are mounted on opposite ends of a wooden or metal shaft on which the drilling cable is wound, the free end of the drilling cable passing up through the derrick to a metal sheave on the derrick "crown," and thence vertically downward to the drilling tools in the well. The bull wheels are used for applying the power in hoisting the drilling tools out of the well. A band brake bearing on the face of one of the two bull wheels serves to control the descent of the tools when they are being lowered into the well, and to hold them suspended when necessary.

On the opposite end of the band wheel shaft from that on which the crank is attached, there is mounted a sprocket wheel controlled by a clutch. An endless chain from this sprocket drives another large wheel called the "calf wheel," on the shaft of which the "calf line" is wound. This is a substantial cable, usually of steel, which passes up through the derrick to the crown and is threaded back and forth between four stationary sheaves ("crown blocks") and three traveling sheaves mounted in a massive frame to which the "dead line" or end of the cable is also fastened. This "hoisting block," as it is called, is used in lowering, lifting and supporting the heavy strings of casing suspended in the well. A large hook and special pipe clamps, called "casing elevators," provide a means of attaching the casing to the hoisting block. A band brake on the rim

of the calf wheel serves to control the descent of the casing, or to hold it suspended when the calf wheel clutch is disengaged.

The "bailer," by means of which the material loosened by the drill is removed from the well, is suspended on a light steel cable or "sand line," which passes over a sheave at the crown of the derrick and thence downward, outside of the derrick, to the "sand reel," a small metal drum mounted on a horizontal steel shaft. The sand reel and its shaft and bearings are mounted on a movable cradle which permits of a friction pulley keyed to the same shaft being brought to bear against the face of the band wheel, thus revolving the sand reel, winding up the sand line and raising the bailer. The bailer is lowered by gravity, a postbrake on the sand reel friction pulley serving to control the speed.

It will be observed that the mechanism described in the foregoing paragraphs has four chief functions: (1) to churn the drilling tools up and down in the well, thus accomplishing abrasion of the material at the bottom; (2) to lower the drilling tools into the well and hoist them out, by unwinding or winding the drilling cable on the bull wheel shaft; (3) to raise, lower and support the heavy metal casing with the aid of the calf line, or casing line, and calf wheel; and (4) to hoist and lower the bailer, used in excavating the material loosened by the drill. In addition to the main features of the rig outlined above, there must be the necessary brakes and levers for controlling the engine and the various wheels, and a great variety of tools and implements useful in conducting the work. These will be considered in greater detail in the following pages. Application of the several forms of power to cable drilling is discussed in Chap. XIV.

The Derrick

In addition to supporting the various tools, wheels and cables in position, derricks have the function of providing something to pull against in handling the long lines of heavy tools and casing, which may aggregate many tons in weight. On account of this great strain put upon it, the derrick must be braced in all directions and securely anchored on firm foundations, so that it will not collapse or be pulled over. It must be high to provide sufficient head room between the sheaves at the crown and the mouth of the well at the derrick floor, in which to manipulate the long strings of drilling tools and casing.

Derricks may be constructed of either wood or steel. Common pine and hemlock are generally used in the construction of wooden derricks in the American fields. Harder woods, such as oak, beech or maple, are used in certain of the posts, sills, wheels, shafts, crown blocks and other members subjected to great strain or wear. Rarely creosoted timber will be used. Steel derricks may be constructed either of the usual rolled

sections—angles, channels, I-beams, etc.—or of tubular forms. For housing the lower portion of the rig and derrick, galvanized corrugated iron is often used instead of wooden sheathing. While somewhat more expensive than wood, galvanized iron is fireproof and longer lived. The derrick footings may require the use of concrete, though they are often built entirely of wood.

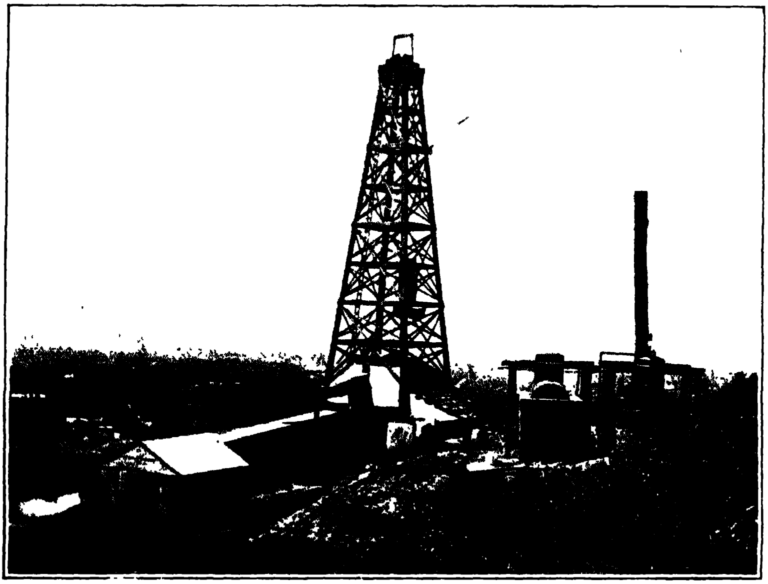


FIG. 35.—An 82-foot standard cable rig, California type.

Derricks for cable drilling vary in height from 60 to 82 ft., they are from 16 to 24 ft. square at the base, and from 4 to 6 ft. square at the top. The size of the derrick is designated by the height and the area of the floor space enclosed within the four corner posts or legs. Thus, a 20- by 74-ft. derrick has a floor space 20 ft. square, and is 75 ft. high. This size has been used more than any other in the western American oil fields, though the tendency in recent years has been toward larger, particularly higher structures. It is seldom that the floor space is made less than 20 ft. square, and the heavier types are 22 or 24 ft. square. The 24- by 82-ft. derrick is a commonly used size for cable drilling in deep territory (see Fig. 35).

Wooden Derricks.—A 20- by 74-ft. derrick requires some 20,500 bd. ft. of lumber and timber. For a 24- by 106-ft. derrick, a size commonly used in rotary drilling, 31,700 bd. ft. are necessary. These figures include all wooden parts of the rig except the bull and calf wheels. Rough, undressed lumber and timber is used throughout, except in the construction of the wheels.

The derrick is supported on short posts, which rest in turn on a suitable foundation of either timber or concrete. The posts mentioned support the principal foundations or sills; these are given various names according to their positions in the structure.

The derrick consists of four upright members, called "legs," forming the corners of the structure, braced by horizontal girts and diagonally placed braces. The legs are constructed by nailing 2- by 10-in. and 2- by 12-in. planks together to form a 90 deg., V-shaped trough, each side of the trough taking the direction of one side of the derrick. Ordinarily one set of these legs extending to the full height of the structure will be strong enough. Derricks designed for deep well drilling, using heavy equipment, are constructed with two such trough-shaped legs, one within the other, at each corner, the second or outer set of legs being known as "doublers." For moderate depths, doublers may be used only to reinforce the lower 18 ft. on each leg, but in many heavy rigs they extend to the full height of the derrick. In exceptionally heavy derricks, a third set may be used to reinforce the lower 18 ft. on each leg.

All four sides of the derrick are battered to a slope of from 1 in 5 to 1 in 7, depending upon the height of the derrick and the size at the bottom and top. The horizontal girts and inclined braces are usually of 2- by 12-in. or 2- by 8-in. material. They serve to hold the legs in position and take a portion of the compressive strain put upon the structure during drilling operations. In addition to the usual braces and girts just mentioned, heavy derricks requiring additional strength are "sway braced" by adding another set of girts on the outside of the legs, opposite every other set of inside girts, and placing long diagonal braces between the outside girts (see Fig. 95).

The engine and belt houses are built of 1- by 12-in. lumber, as is also the lower portion of the derrick, if it is to be housed. For the walk connecting the derrick and the engine house, and the flooring throughout the structure, 2-in. planks are used. A rack of 6- by 8-in. timbers is built beside the walk for the purpose of holding casing, tubing, tools and miscellaneous equipment that may be necessary from time to time as drilling proceeds.

Derrick Construction.—After the site selected for the well has been cleared of trees, brush and other vegetation, excavations are made if necessary for the derrick footings, the mud sills and the engine and belt house foundations. Usually at this time the cellar will also be dug, and if rotary equipment is to be used, the slush pit will be excavated. The cellar, which consists of a vertical shaft about 8 or 10 ft. square with the spot selected for the well as its center, is not always necessary but is convenient in inserting and manipulating casing, particularly in wells drilled with cable tools through soft formations which have a tendency to cave. In such formations it is often necessary to allow the casing to follow closely the progress of the drilling tools. The depth of the cellar should therefore be about 20 ft. below the derrick floor in order that a full length of pipe may be added to the casing in the well without interfering with the operation of the temper screw. For rotary drilling, the cellar is generally unnecessary except as a means of setting a conductor.

Erection of the rig and derrick begins with the placing of the mud sills and the main, nose, sub and tail sills.[12] The derrick footings, which consist of 2-in. plank or concrete piers are meanwhile prepared, and when these are completed, short posts are mounted upon them of proper length to support the derrick sills level with the mud sills. The derrick floor will next be put down, and the legs, braces and girts of the derrick assembled and securely nailed together and surmounted by the crown, water table, bumpers and crown block (see Fig. 34).

The rig posts are next placed in position on their respective sills—the jack post which supports the band wheel and crankshaft, the bull wheel and calf wheel posts and the knuckle post, the back brake and bracing for support of the sand reel. The

band wheel, bull wheels and calf wheel are next assembled and placed in position, and the engine block is placed on its foundations. The Samson post and walking beam are not placed until the bull wheels may be used for drawing them into position. The sand reel and friction pulley are not mounted until the band wheel is in position, care being taken to make certain that the friction pulley runs true with the band wheel. Finally, the framing and housing about the engine house, the belt house and the lower portion of the derrick is installed, the plank wall connecting the engine house and derrick is laid, and the casing rack is built. Attention must then be given to many details, including proper placing and adjustment of the rig irons, wedging and bracing the sills and posts, guying the derrick and general "rigging up" or preparing the equipment for drilling operations.

A wooden "standard" rig and derrick for cable drilling, or a "combination" rig for either cable or rotary drilling, can be erected and rigged in from 15 to 20 days by a rig-building crew of five men. A "rotary" rig can be assembled in less time, often from 10 to 15 days.

Setting the Conductor.—In order to exclude surface water and debris from the well, and in part also, to assist in keeping the drilling tools aligned, a "conductor" of drive pipe, riveted steel "stove pipe," corrugated steel pipe or wooden staves is installed in the cellar and rigidly braced. This conductor extends downward from the floor of the derrick, usually to bedrock, unless this lies at too great a depth. When the superficial deposit of earth is too thick to permit of setting the conductor on a solid foundation, 2 or 3 lengths of drive pipe coupled together and equipped with a sharp steel shoe at the lower end may be driven to bedrock with the aid of the drilling tools. The conductor is of somewhat greater diameter than that of the well itself, and may be removed or cut off a little above the level of the cellar bottom after the well has attained a depth of 100 ft. or more.

Steel derricks and rigs are of two general types: first, structural steel derricks, made up of the ordinary structural shapes; and second, tubular steel derricks, in which the various members are made of sections of steel pipe.[17] Mild steel similar to that used in ordinary structural work is the material used. In moist climates near the sea, galvanized metal, which more successfully resists corrosion, may be used to advantage.

The Woodworth derrick manufactured by the Carnegie Steel Company, utilizing structural steel forms, is illustrated in Fig. 36. Steel angles, 4 by 4 in., or 6 by 6 in., in cross-section, and from $\frac{5}{16}$ to $\frac{1}{2}$ in. thick, are used for the legs, it being customary to use thicker sections toward the bottom where the strain is greater. The girts and braces are also constructed of steel angles, but are smaller and lighter. This type makes use of square root angles or web plates through which the various members making up each joint are bolted. Eight bolts are used at each joint. Another type, the Yorke derrick, is built of structural angle steel and makes use of a patented joint utilizing lock bolts. These bolts may be put in place before erection, connection being made by slipping slots, cut into the steel angles, over the bolts and tightening the nuts. A derrick of this type can be erected or dismantled in a few hours. The Foukes structural steel derrick utilizes a patented type of joint, consisting of a steel plate bent around the leg section. The girts and braces are attached by three bolts at each joint passing through lugs on the bent plates.

The tubular steel derrick has attained a considerable popularity in certain districts, replacing to some extent the earlier form of wooden derrick. The legs of these tubular steel derricks are made of steel pipe of varying weight, depending upon the position of the member in the structure. The different parts are fastened together by special clamps of forged steel to which the girts and braces are attached by means of bolts (see Fig. 37). Tubular derricks of "duplex" or "triplex" design have one or two pipes telescoped within the outer pipe to give additional strength. It is claimed that two

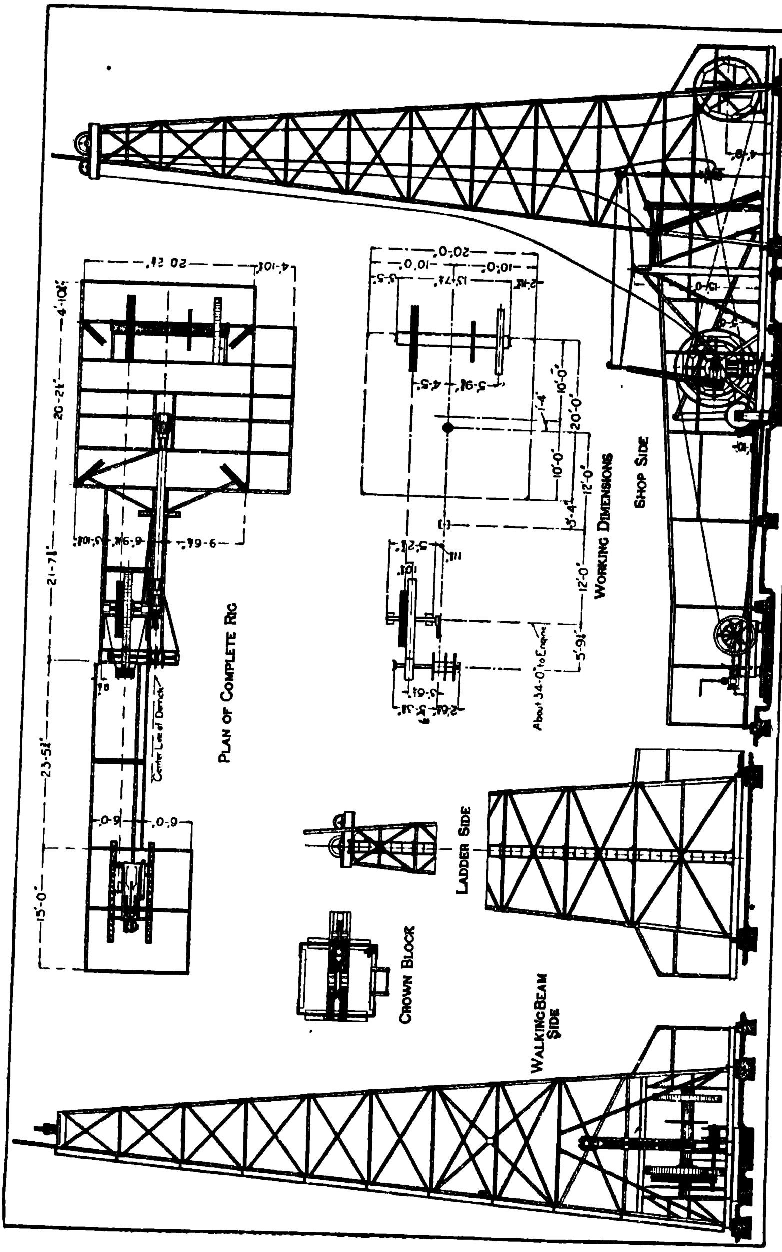
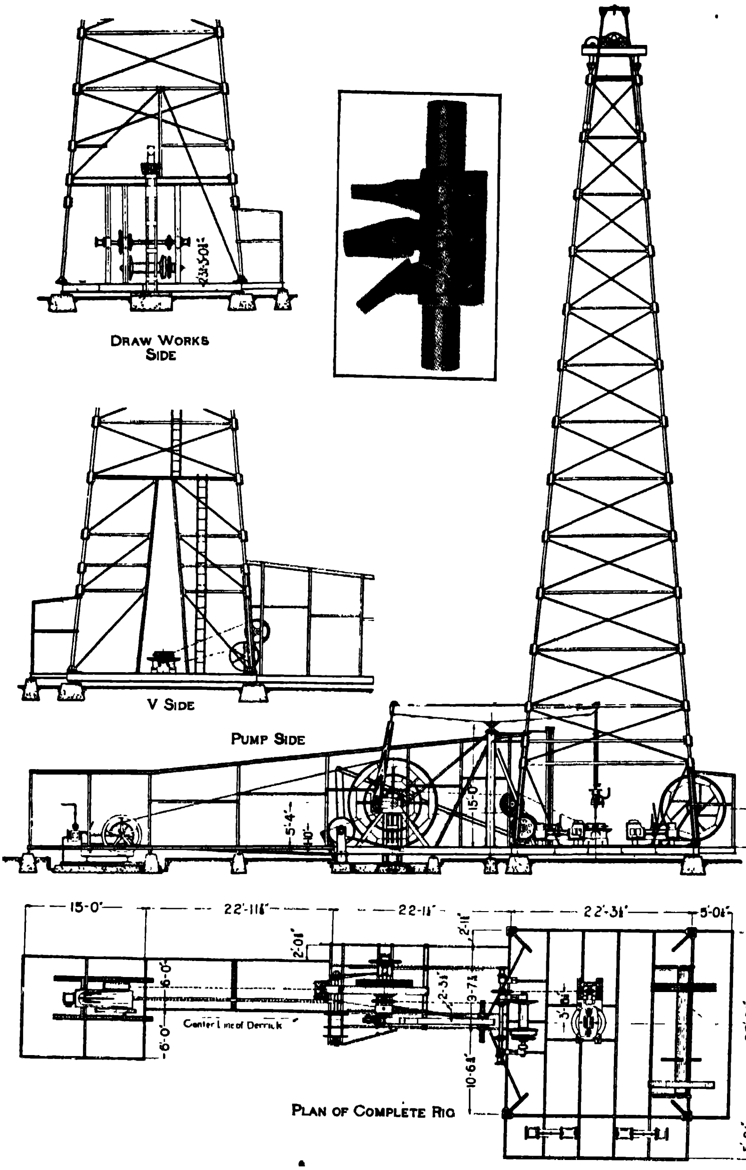


Fig. 36.—Woodworth 80-foot structural steel rig for cable drilling.

men can erect a full-sized derrick of this type in one day. Small and light tubular steel derricks are made for erection at pumping wells, which are strong enough to



(*Lee C. Moore Co., Pittsburgh, Pa.*)

Fig. 37.—Tubular steel derrick and combination steel rig.
Half-tone insert shows detail of derrick leg joint.

withstand the occasional repair and cleaning operations, but not heavy enough for drilling operations.

Various combinations of wood and steel in the construction of derricks have also been worked out, particularly to facilitate dismantling and reassembling at a new site. One of these that has been used to some extent in prospecting work uses wooden legs and girts, with braces made of round steel rods. At the joints, all members are bolted through metal angle plates. The metal braces are adjusted to take most of the strain by means of adjustable turnbuckles.

In addition to the use of steel in building the derrick proper, steel framing and corrugated iron sheathing is also provided for the belt house and engine house by most steel derrick designs. The foundations may be of timber if desired, but special steel sills and posts may also be had.

Steel walking beams, pittmans, band wheels, calf wheels and bull wheels are also available, built of standard rolled steel sections. The steel wheels are usually faced with replaceable oak cants to provide a wooden braking surface and a less abrasive surface for the ropes and belt to bear upon. The use of steel in the construction of moving parts of the rig, particularly in the construction of the wheels, provides a much better type of working gear than is possible with wood: mechanically superior, easier to keep in alignment and adjustment, more reliable under strain and longer lived. There seems to be little disagreement among drillers over the superiority of metal construction in comparison with wood in the building of these working parts. The only disadvantage is that they cost more. It is not unusual to wear out two or three sets of wooden bull and calf wheels in the drilling of a single deep well, while the steel wheels practically never wear out, except for the replaceable wooden cants.

Advantages and Disadvantages of Wooden and Steel Derricks.—Wooden derricks are generally preferred by drillers particularly for cable drilling, because they are said to be more flexible than steel and respond better to the churning motion of the tools.

Since the derrick is usually left at the well after the drilling operations are completed, to facilitate subsequent repair work, the rate of deterioration of the materials used is an important consideration. Wooden derricks are often built of common pine, which will last in the climates prevailing in most American oil fields, perhaps 5 or 10 yr. without noticeable decrease in strength. If the life of the well is likely to be greater than 10 yr., in some climates timber treated with a preservative, such as creosote, may be preferable and more economical in the end. The average life of treated timber is probably from 3 to 5 times that of the untreated material, but its cost is materially greater. Steel derricks, if properly protected against corrosion, are practically permanent, and suffer very little deterioration.

The possibility of fire is also an important consideration in the selection of derrick materials. Here, of course, steel has a great advantage over wood. Creosoted timber offers a greater fire risk than untreated wood.

Again, if there is probability of a derrick being moved from one location to another, as in prospecting work, the steel rig and derrick is much to be preferred. Tearing down and removing the heavy spikes used in the construction of wooden derricks is likely to cause considerable damage to the timber members; while the steel structure, being fastened together with bolts, is readily disassembled. Because of the opportunity for better design in proportioning the various parts of a steel rig, particularly in the rig posts and sills, the steel derrick is lighter than the wooden derrick by some 25 or 30 per cent. A standard 80-ft. Woodworth rig and derrick, including foundations, bull and sand wheels, house framing, corrugated sheathing, etc., weighs only 45,300 lb. as compared with approximately 60,000 lb. for a wooden rig and derrick of the same size and strength. It is claimed that the collapse of a properly erected steel derrick, even under severe working conditions, is an impossibility. This gives a feeling of security to the workmen that is not always enjoyed when working under a wooden derrick.

Though the first cost of a steel derrick is normally greater than that of a wooden derrick, the cost of lumber is continually increasing as our forests are denuded, and the time may soon come when difference in cost as between the two types will count for little. The cost of erection is also less for a steel derrick, and when the comparatively short life of the wooden structure is considered, together with the fire risk, it is apparent that the steel derrick is destined eventually to displace the wooden derrick.

The design of a derrick involves consideration of the character of loading and the direction and intensity of the various forces imposed on the structure. Considerations of transportation and erection cost and economy of material require that the structure be as light as may be consistent with the service required of it. The ordinary processes of drilling, bailing and handling casing provide comparatively little strain on the derrick, but a safety factor of at least 4 should be allowed in order to provide for the unusual and suddenly applied strains imposed at certain times, such as in the "pulling" of casing or in jarring up during fishing operations.

Wind pressure also must be taken into account in the design, 30 lb. per square foot of exposed surface being a sufficient allowance in most regions. This is equivalent to the pressure imposed by a wind moving at the rate of about 70 miles per hour. Tubular forms have a considerable advantage in this respect over designs which present a broad flat surface to the wind.

The influence of wind pressure on the structure as a whole is offset largely by the use of guy wires to near-by stationary objects on the ground, or to "deadmen" of timber, steel or concrete buried in the earth. From 8 to 24 guy wires are used, that is, from 2 to 6 on each leg. These are attached at two or three points between the derrick crown and the lower panel, and are led off from the derrick in the direction of the diagonal plane through the opposite leg. In cases where 6 wires are used on each leg, they may be arranged with 3 wires in each of two planes, paralleling the sides of the derrick panels. A suitable type of guy line is one composed of 7 steel wires twisted together to form a strand which may be had in diameters ranging from ⅛ to ½ in. The ¼- and ⅜-in. sizes are widely used. The guy wires should be anchored at points not less than 100 ft. from the derrick. Serious damage has resulted in some American fields through inadequate wiring and failure of guy lines and deadmen during heavy windstorms.

A study of the form of the derrick and the direction of the forces applied will show that there is comparatively little eccentric loading, the power opposing the loads being applied vertically, or nearly so, except in so far as transmission to the wheels is concerned. The legs, of course, are under direct compression at all times, both from the live load imposed and from the dead load of the structure itself. The batter of the sides of the structure would tend to put the girts and braces toward the top under compression, while those toward the bottom are theoretically under tension.

Some parts of the rig, such as the walking beam and the wheel supports, are subjected to heavy bending stresses, which must be offset where possible by suitable braces. Joints between posts and sills must be carefully framed to prevent movement, particularly during oscillation of the walking beam. Drive keys must be provided at all such joints to take up clearances and prevent movement and loss of alignment.

The actual strain likely to be imposed is not susceptible of close measurement, and can only be estimated approximately. The maximum is probably attained when the structure is required to withstand the strain necessary to pull apart a string of heavy casing that has become "frozen" in the well, or so bound with loose material from the walls that it cannot be moved. Some drillers urge that the structure should be strong enough to withstand the strain imposed by "parting" a string of 12-in.

40-lb. casing. Steel derricks have been designed for working loads varying from 92,000 to 294,000 lb.

The height of the derrick is determined in the case of the cable rig by the length of the string of drilling tools and hoisting gear that must be suspended between the crown block and the mouth of the well. In the case of the rotary derrick, the number of 20-ft. lengths of drill stem per "stand" is the determining factor.

THE RIG WHEELS

The large wheels which provide braking surfaces and a means of applying power in the various operations of hoisting and lowering the tools, casing and the bailer, are usually built of wooden segments, cants and arms, rigidly nailed or bolted together. They are bolted to cast-iron gudgeons which provide a means of fastening them to the wooden or metal shafts on which they revolve.

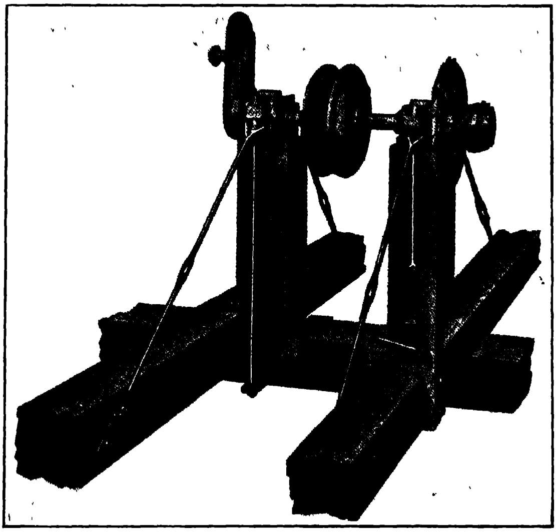


FIG. 38.—Showing assembly of crank, wrist pin, crank shaft, band wheel gudgeons, sprocket, clutch, braces and supporting posts and sills.

The band wheel is a solid wooden wheel varying from 9 to 12 ft. in diameter, built of lumber segments held together by numerous bolts. The wheel has a smooth face, 12 in. wide, on which bear the belt from the engine pulley and the sand reel friction pulley. The wheel is bolted at the center to two cast-iron hubs, one on either side, which provide a means of keying the wheel to the crankshaft on which it turns. Attached to one side of the band wheel is a wooden tug pulley 7 ft. in diameter, on the rim of which one or two grooves are cut to receive the bull rope or ropes which drive the bull wheels. The steel crankshaft is supported by two metal bearings, one on either side of the wheel, mounted on two upright jack posts (see Fig. 38).

The bull wheels, two in number, are mounted, one on each end of an oak shaft 14 or 15 ft. long and 16 or 18 in. in diameter. Sometimes a shaft of smaller diameter made of steel pipe is used. The wheels are 7½ or 8 ft. in diameter, built of oak cants and arms. The wheels are from 9 to 12 in. wide, one faced to a smooth braking surface for a metal band brake which bears upon it, and the other grooved to receive the drive from the bull rope or ropes. The bull wheel shaft, when built of

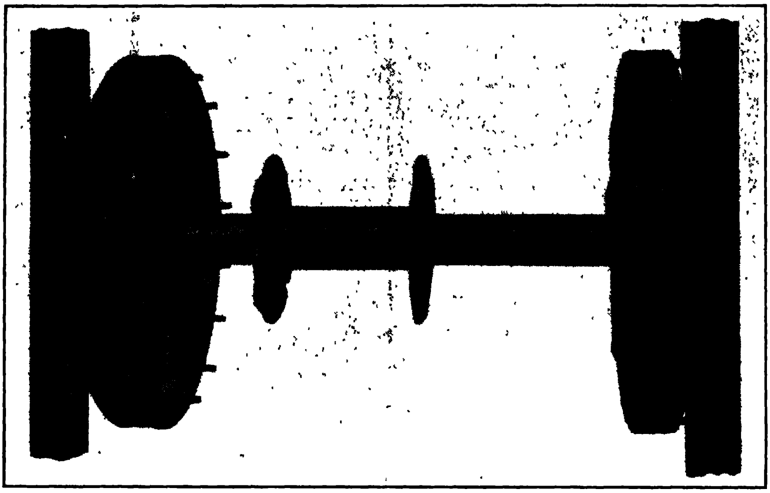


FIG. 39.—Bull wheels, showing shaft, spooling flanges and supporting posts.

wood, is round in the center, but is usually octagonal at the ends in order to provide a positive grip for the metal gudgeons which serve as the hubs of the wheels, to which the arms or spokes are bolted (see Fig. 39). The metal gudgeons at the ends of the bull wheel shaft are supported in metal boxes, mounted on substantial wooden "bull wheel posts," braced between the derrick sills and the first horizontal girt. Around the side of each bull wheel, 16 wooden handles are inserted. These are useful in turning the wheels by hand when necessary in taking up slack in the drilling cable. Mounted on the bull wheel shaft are two adjustable "spooling flanges" which prevent the drilling cable from slipping on the shaft and confine the portion of the cable in actual use to the central section.

The calf wheel is usually built more substantially than the bull wheels, because of the greater strain to which it is subjected, but it is similarly constructed of oak cants and arms. Heavy calf wheels have twice as many arms as the ordinary bull wheel, the arms being braced in pairs in opposite directions (see Fig. 40). The calf wheel shaft is similar in its construction and equipment to the bull wheel shaft described in the preceding paragraph, except that it is shorter. It is

supported by a pair of heavy upright posts and turns on steel gudgeons resting in metal boxes. Mounted on one side of the calf wheel rim is the sprocket wheel which receives the chain drive from the crankshaft sprocket. An earlier type of calf wheel using a rope drive instead of the

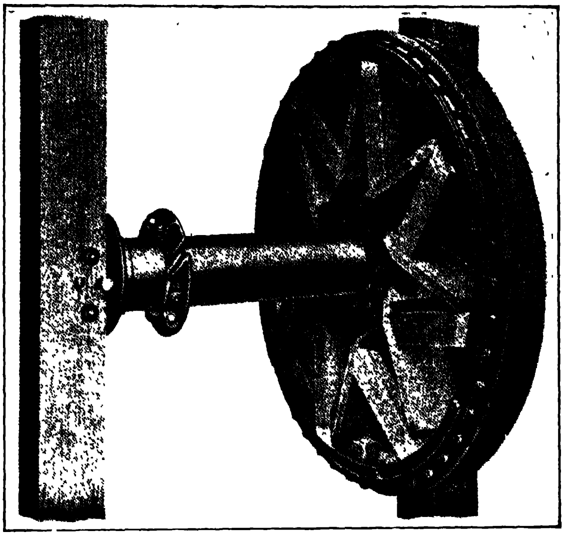


FIG. 40.—Calf wheel, showing shaft, sprocket and supporting posts.

chain drive is now almost obsolete. Frequently, the steel surface of the calf wheel shaft is lagged with hemp rope to prevent abrasion of the casing line wound on it. A steel band brake operated by a lever bears on the

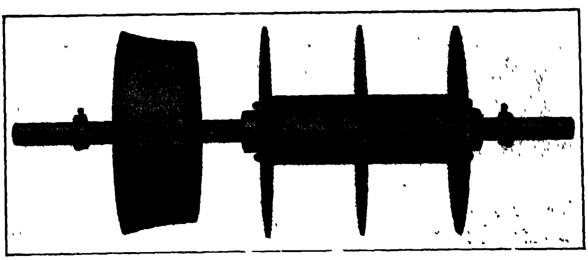


FIG. 41.—Sand reel, shaft and drive pulley.

wooden face of the calf wheel and prevents it from turning when it is required to support heavy loads.

The sand reel is an all-metal drum, keyed to a steel shaft to which is also attached a cast-iron friction pulley (see Fig. 41). On the drum, the sand line is wound. The friction pulley may be brought to bear against the face of the band wheel, causing the sand reel shaft and drum to

revolve. The drum is usually about 3 ft. long and varies from 6 to 20 in. in diameter. The drum flanges are often about 3 ft., and the friction pulley about 40 in. in diameter. The sand reel shaft is supported by metal bearings mounted on a movable timber frame pivoted at its lower end on two heavy "sand reel posts." This frame may be drawn forward by the "sand reel lever" until the friction pulley bears against the revolving band wheel, or it may be forced backward against a wooden post which bears against the friction pulley, serving as a brake to control the descent of the bailer.

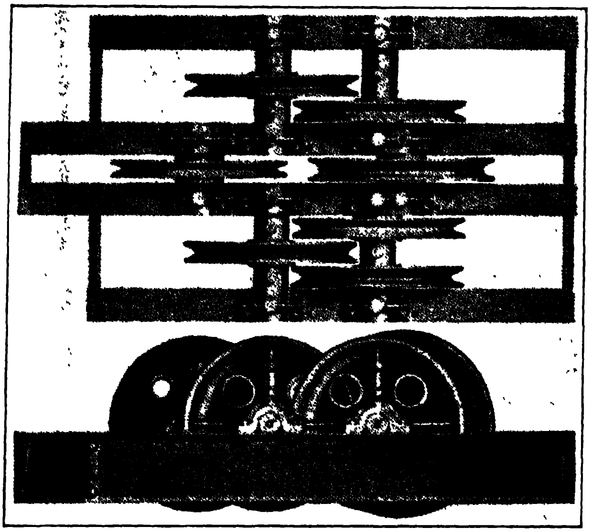


FIG. 42.—Seven-sheave crown block for combination rig.

The crown block contains 6 or 7 cast-iron pulleys ranging from 24 to 36 in. in diameter, supported by metal boxes, bolted to substantial oak or steel supports (see Fig. 42). These sheaves should be of large diameter in order to avoid sharp bends in the cables passing over them. The largest sheave, usually 36 in. in diameter, is the "crown pulley" over which the drilling cable passes. The "sand line pulley" is of intermediate size, often 30 in. in diameter. The four (sometimes 5) smaller sheaves are provided for the support of the casing line, which is threaded back and forth between them and the sheaves in the hoisting block. The number of sheaves provided for the casing line depends upon the load likely to be imposed, the mechanical advantage in favor of the power being in direct ratio to the number of ropes extending between the crown block and the hoisting block.

The Rig Irons.—All of the metal parts used in the construction of the standard cable rig, with the exception of the nails, bolts, sand reel and guy wires, are known collectively as the "rig irons." They include such

items as the gudgeons, shafts and boxes of the wheels, the crank and wristpin, the sprocket wheels chain and clutch, a metal stirrup for the pittman, the center irons or metal bearing on which the walking beam oscillates, together with numerous bolts and fastenings. Rig irons are furnished in complete sets by the manufacturers, varying in size and weight with the size of the rig for which they are intended. The size is designated by the diameter of the crankshaft, which may vary from 4 to 7½ in. Rig irons of the 4- and 5-in. sizes are used only for shallow wells and light work, the 6-in. size being commonly employed for heavier duty. Aside from differences in size and weight, there is some variation in design of rig irons, and in the list of parts furnished in sets. Thus, the California pattern, Oklahoma pattern and Pennsylvania pattern rig irons differ from each other in certain respects, being designed particularly for the type of rigs favored in the regions after which they are named.

Cables and Cordage

The selection of material for the cables and ropes used in driving the wheels, operating the drilling tools and bailer and supporting the casing, must receive careful attention. Both hemp and manila sisal and steel wire are used in the construction of these cables, and special forms have been devised to adapt them better to the purposes for which they are used.

The Drilling Cable.—Probably the most important of the cables used in the standard rig is the drilling cable which serves to connect the drilling tools in the well with the power at the surface. When drilling is in progress, the drilling cable is suspended from the walking beam to which it is attached by the temper screw. The surplus cable is carried up through the derrick over the large central crown pulley, and thence down to the bull wheel shaft on which it is coiled. When the drilling tools are being lowered or hoisted, or are suspended in the derrick, the tension in the drilling cable is transferred directly to the bull wheels and crown pulley.

The duty imposed on the drilling cable is severe. Not only must it support the weight of the tools (often between 1 and 2 tons), but the dead weight of the cable itself may be as great as that of the tools when operating at a depth of 2,000 or 3,000 ft. Furthermore, the strain imposed by the alternate application and relief of tension with each stroke of the tools, and the wear resulting from rubbing of the outer strands of the cable on the rough rock walls of the well and the metal casing, also tend to weaken it and to shorten its useful life.

Hemp Drilling Cables.—Both manila fiber and steel wire have been widely used in the construction of drilling cables, but the former is generally preferred where its strength is adequate on account of its greater elasticity. With proper adjustment of the temper screw and motion of the walking beam, a much harder blow may be

struck with the tools when they are suspended on a hemp cable than is possible with steel, because of the greater elasticity of the hemp cable, which materially increases the length of stroke. Furthermore, if the temper screw is adjusted so that the tools strike bottom on the "spring" of the line, they rebound quickly when the blow has been struck, thus dislodging the bit from the cuttings which otherwise tend to hold it. The hemp cable imposes less strain on the derrick, and makes hole faster than does the steel cable.

Hemp cables of 2, 2¼ and 2½ in. diameter have been widely used in the drilling of wells up to 1,500 or 2,000 ft. in depth, but at greater depths the large-sized cable necessary becomes expensive and impracticable, and a steel cable must be substi-

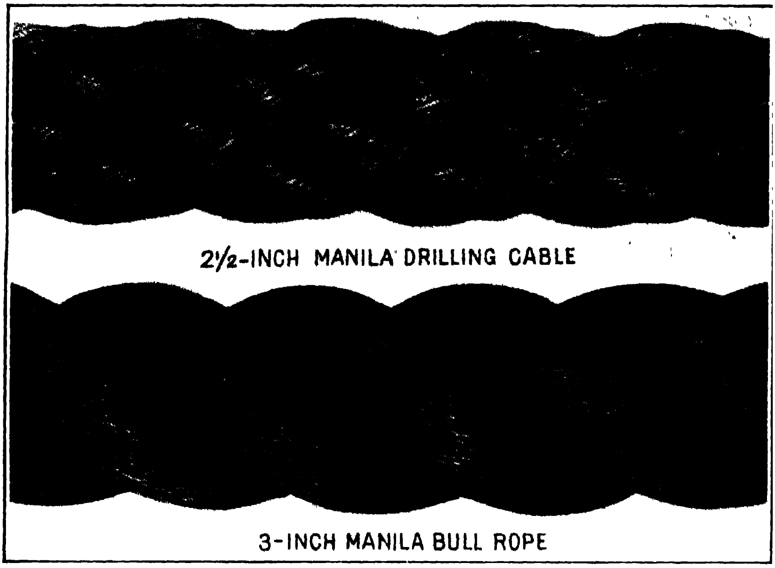


FIG. 43.—Types of cordage used in cable-drilling rigs.

tuted. During drilling operations the well must be at least partially filled with water, and the friction developed by the motion of a rough manila cable of large diameter, through this water, seriously reduces the force of the blow struck by the tools and increases the power consumption. The displacement of fluid in the well by so large a cable is also excessive in a hole of even moderate diameter, so that the tools do not drop promptly on the down stroke of the walking beam, as they should for best results.

Manila drilling cables are made of a selected grade of manila hemp in long fibers, twisted especially hard to withstand the severe strain to which they are subjected. The fibers composing the strands are given a left "lay" or twist, while the strands making up the ropes are given a right lay. The three ropes composing the cable are tightly twisted in the reverse direction to the twist of the cable itself in order to prevent the cable from kinking readily, and so that the cable will not unwind when subjected to heavy loads. This construction (see Fig. 43) results in the individual strands running parallel with the axis of the rope and there is less abrasion of the outer strands than would be the case if they assumed an agular position. To achieve an equal distribution of the load on the three ropes composing the cable, the lay of the strands, ropes and cable must be perfectly uniform throughout.

The strength of a hemp cable depends directly upon the strength of the individual fibers and the means adopted for preventing them from pulling apart.[1] They may fail either through breakage of the fibers, or by the pulling apart of the several fibers which make up the strand. Since the original fibers will seldom be more than 3 ft. long, and often a good deal less than this, it is evident that the strand depends for its strength upon the friction developed between the individual fibers by twisting. If a strain is put upon the rope in excess of the frictional resistance to movement of the fibers, they pull apart or slide on each other. Wetting the hemp fibers will decrease their angle of friction. It is found that a hemp cable properly designed to develop the proper amount of friction to prevent it from pulling apart when dry, may have as much as 30 per cent less strength when wet. This of course has no bearing on the failure of the rope by direct breakage of the fibers.

The weight and strength of hemp cables of this type will vary somewhat with the quality and condition of the fiber and the care taken in their construction. Table VIII presents what are considered by a large rope manufacturing company to be average figures for the commonly used sizes of drilling cables. Hemp drilling cables

TABLE VIII.—WEIGHTS, SIZES AND STRENGTHS OF MANILA DRILLING CABLES*

Diameter, in.	Circumference, in.	Pounds per foot	Ultimate strength of new rope, lb.
1½	4½	.949	17,000
1¾	5¼	1.280	25,000
2	6	1.580	30,000
2¼	7	1 790	37,000
2½	7½	2 330	43,000

* Data furnished by Tubbs Cordage Company of San Francisco, Cal.

usually stretch about 50 per cent of their original length during continued use, so that a 1,500-ft. cable will often serve for the drilling of a 2,000-ft. hole. Hemp and manila rope deteriorate rapidly in dry climates, becoming dry and brittle and losing much of their strength and pliability. When not in use, hemp cable should be stored in a cool and moist place. Storehouses carrying a considerable stock of hemp or manila cordage should be equipped with a humidor for its preservation during the period of storage.

Steel Drilling Cables.[1]—The elasticity of the hemp cable is to a large extend lacking in the steel cable until the length reaches a thousand feet or more, and in some regions it is customary to use the steel cable only after this depth has been attained with a hemp cable. While something is undoubtedly sacrificed in the use of the steel cable through its lower elasticity, there are certain compensating advantages which often make its use preferable. For example, in drilling with a high-fluid level in the well, the smaller diameter of the steel cable results in less displacement of water, and because of its relatively smooth outer surface it moves through the fluid with less friction. Furthermore, it is stronger, has a longer life and for deep wells is cheaper.

In order to secure the maximum of pliability the steel cable is made of a large number of wires, usually 114, assembled in 6 strands of 19 wires each, and twisted around a hemp core which provides a cushion for the wire strands and prevents them from abrading each other (see Fig. 44). For light service, a rope constructed of 6

strands of 7 wires each is sometimes used. The steel of which the wires are composed is preferably a high-grade crucible steel or plow steel, commonly used in hoisting cables subjected to severe abrasion. Table IX gives the sizes, weights and ultimate strengths of steel cables of this type. Tables X and XI show the depths to which two commonly used sizes may be employed for tools of different weight and for varying lengths of stroke. For light work and in holes of small diameter, ¾-in. steel cables are commonly used, but for heavy service, cables ranging in diameter from ⅞ to 1½ in. are customary.

(*American Steel & Wire Co., New York*).
FIG. 44.—Steel wire drilling cable, 6 by 19.

In determining the allowable working strain on a steel cable used in oil well service, it is customary to adopt a safety factor of 5; that is, the cable used should have a breaking strength approximately 5 times the estimated working load. This latter quantity, however, cannot be determined precisely, inasmuch as it is influenced by many conditions the effect of which can only be estimated. Probably every cable employed in oil well service is at times subjected to tensile stresses approaching its breaking strength, and since the elastic limit of steel is only about 60 per cent of the breaking strength, the character of the steel will be materially altered and the useful life of the cable shortened by overstrain.

TABLE IX.—WEIGHTS, SIZES AND STRENGTHS OF STEEL DRILLING CABLES AND CASING LINES*

Crucible Steel, Extra Strong, 6 by 7 Wire Cable

Diameter in.	Circumference, in.	Approximate weight per foot, lb.	Approximate strength in tons of 2,000 lb.	Maximum working load in tons of 2,000 lb.	Diameter of drum or sheave advised, ft.
1½	4¾	3.55	73.00	14.60	11
1⅜	4¼	3.00	63 00	12.60	10
1¼	4	2.45	54.00	10.80	9
1⅛	3½	2.00	43.00	8.60	8
1	3	1.58	35.00	7.00	7
⅞	2¾	1.20	28.00	5.60	6
¾	2¼	.89	21.00	4.20	5
11/16	2⅛	.75	16.70	3.30	4¾
⅝	2	.62	14.50	2.90	4½
9/16	1¾	.50	11.00	2.20	4
½	1½	.39	8.85	1.80	3½
7/16	1¼	.30	6.25	1.25	3
⅜	1⅛	.22	5.25	1.05	2¾

* As manufactured by the American Steel and Wire Co.

TABLE IX.—WEIGHTS, SIZES AND STRENGTHS OF STEEL DRILLING CABLES AND CASING LINES* (*Continued*)

Crucible Steel, Extra Strong, 6 by 19 Wire Cable

Diameter, in.	Circumference, in.	Approximate weight per foot, lb.	Approximate strength in tons of 2,000 lb.	Maximum working load in tons of 2,000 lb.	Diameter of drum or sheave advised, ft.
1½	4¾	3.55	73.0	14.60	6.0
1⅜	4¼	3.00	64.0	12.80	5.5
1¼	4	2.45	53.0	10.60	5.0
1⅛	3½	2.00	43.0	8.60	4.5
1	3	1.58	34.0	6.80	4 0
⅞	2¾	1.20	26.0	5.20	3.5
¾	2¼	.89	20 2	4.04	3.0
⅝	2	.62	14.0	2.80	2.5

* As Manufactured by the American Steel and Wire Co.

TABLE X.—DEPTHS TO WHICH CABLE TOOL DRILLING MAY BE CONDUCTED WITH ⅞-IN. STEEL DRILLING CABLES, USING TOOLS OF DIFFERENT WEIGHT WITH VARYING STROKE*

Weight of tools, lb.	⅞-in. diameter oil well drilling cable						
	18-in. stroke, ft.	24-in. stroke, ft.	30-in. stroke, ft	32-in. stroke, ft.	36-in. stroke, ft.	40-in. stroke, ft.	42-in. stroke, ft.
2,000	8,333	5,833	4,333	3,957	3,333	2,833	2,619
2,500	7,917	5,416	3,917	3,541	2,917	2,417	2,202
3,000	7,500	5,000	3,500	3,125	2,500	2,001	1,786
3,500	7,084	4,585	3,084	2,709	2,084	1,585	1,369
4,000	6,567	4,166	2,667	2,393	1,667	1,169	953
4,500	6,151	3,750	2,250	1,977	1,251	753	536
5,000	5,734	3,333	1,833	1,561	834	337	120

* From Catalog No. 8 of Lucey Corporation.

Care should be taken in selecting the size of sheaves over which the steel cable is passed or the size of drums or shafts on which it is wound, not to have the diameter of the sheave less than about 30 or 40 times the diameter of the cable, and preferably larger. In handling the cable, care should also be taken to avoid sharp bends or kinks which may permanently alter the alignment of the strands and wires, weakening the cable and subjecting it to abnormal abrasion.

It is often necessary to splice wire cable in adding a new length or in replacing a worn section. The "blind splice" is generally used. The strands of each of the two ends are unwound for about 15 ft., the hemp core extracted and the strands of the two ends woven together, one of the strands taking the place of the core. For drilling cables used in very deep wells, it is sometimes desirable to use a larger size of cable on the upper end than on the lower, thus making allowance for the considerable dead load of the cable as greater depths are attained. For example, in

the drilling of a 7,500-ft. well in West Virginia the drilling cable used consisted of sections of 1½-, 1⅛-, 1- and ⅞-in. cables with specially built tapered joints about 150 ft. in length.

The life of steel drilling cable is extremely variable and depends to a large extent on the hardness of the formations penetrated and the care with which it is handled. In some cases a cable may be worn out in the drilling of a single well. In drilling the 7,500-ft. well mentioned in the previous paragraph, ten 8,000-ft. drilling cables and three 9⁄16-in. sand lines were used. In order to secure in some measure the advantage of the more elastic hemp cable, some drillers fasten about 100 ft. of hemp cable on the lower end of the steel cable. This "cracker line," or "snapper line," so called, has in addition the advantage of the small diameter and low cost of the steel cable. It is chiefly used in the oil fields of Illinois, its use in western drilling practice being uncommon.

TABLE XI.—DEPTHS TO WHICH CABLE TOOL DRILLING MAY BE CONDUCTED WITH 1-IN. STEEL DRILLING CABLES, USING TOOLS OF DIFFERENT WEIGHT WITH VARYING STROKE*

Weight of tools, lb.	1-in. diameter oil well drilling cable					
	24-in. stroke, ft.	30-in. stroke, ft.	32-in. stroke, ft.	36-in. stroke, ft.	40-in. stroke, ft.	42-in. stroke, ft.
2,000	6,329	4,810	4,430	3,797	3,291	3,074
2,500	6,013	4,493	4,114	3,481	2,975	2,758
3,000	5,696	4,177	3,697	3,164	2,658	2,441
3,500	5,380	3,860	3,381	2,848	2,342	2,125
4,000	5,063	3,544	3,064	2,531	2,025	1,808
4,500	4,747	3,227	2,748	2,225	1,709	1,492
5,000	4,430	2,911	2,431	1,908	1,393	1,175

* From Catalog No. 8 of Lucey Corporation.

The Casing Line (or "Calf Line").—While the calf line is not subjected to the destructive jar and rapid variation in intensity of strain that is characteristic of drilling operations, the load to be sustained by it is occasionally greater than that imposed on any other cable in the rig. The dead weight of a long column of heavy casing suspended on this cable is alone sufficient to place it under considerable tension, and since this may be exceeded by the frictional resistance of the "formation" on the casing, it is apparent that at times the material will be stressed to a degree that will exceed its elastic limit.

The casing line, it will be recalled from the foregoing general description of the rig, is coiled on the shaft of the calf wheel, the free end being carried over the crown block and threaded back and forth between two or more casing pulleys and the sheaves of the hoisting block. The end of the cable, or dead line, is attached either to the bail of the hoisting block, or to the derrick sills. The number of lines strung between the

derrick crown and the hoisting block determines the tension in the line that is developed during the lifting of a given load. The actual strain may be computed by dividing the weight of the load to be lifted by the number of lines.

The casing line is usually constructed of steel wire, being designed particularly to withstand severe tensional strain. It must be pliable in order that it may bend to the rather small diameter of the sheaves over which it passes without abnormal bending stresses. The construction is quite similar to that of the steel drilling cables described above, the cable built of 6 strands of 19 wires each, with a hemp core, being a common type. Diameters ranging from 3/4 to 1 in. are customary (see Table IX). The material may be softer, however, since the outer strands are not particularly subjected to abrasion, which is an important factor to consider in the selection of a drilling cable. For the drilling of very shallow wells, or in regions where only light casings are used, the casing line may be of hemp instead of steel. In such cases the calf wheel may be omitted in the equipment of the rig and the casing line coiled on a part of the bull wheel shaft; or the drilling cable may be detached from the tools and used for handling casing.

The Sand Line.—The strain which the sand line will be required to sustain will be comparatively small, since the dead load of the bailer and its contents will seldom exceed 2 tons even in the larger sizes of bailers. It is, however, subjected to considerable abrasion, as a result of contact with the walls of the well and casing during operation of the bailer. In addition, it must be sufficiently pliable to bend freely over the sand pulley at the crown block, and to wind without abnormal strain on the 13-in. drum of the sand reel.

For service of this character a steel wire cable composed of 6 strands of 7 wires each, wound on a hemp core (see Table IX), has been found satisfactory. Diameters range from 3/8 to 5/8 in., the 1/2-, 9/16-, and 5/8-in. sizes being commonly used. The smaller sizes are appropriate only in shallow wells. Manila sand lines ranging in diameter from 5/8 to 1 1/4 in. are occasionally used in shallow wells, but their life is short because of the continual surface abrasion and alternate wetting and drying to which they are subjected.

Guy Wires.—For guying derricks it is customary to use a galvanized wire strand composed of 7 wires twisted into a single strand. Available diameters range from 5/64 to 5/8 in.

Bull Ropes.—The rope drive connecting the tug pulley on the band wheel with the rim of the left-hand bull wheel consists of one or two endless hemp or manila ropes, 2 or 3 in. in diameter, built of a large number of small strands loosely twisted together, forming a strong and exceptionally pliable rope (see Fig. 43). The bull ropes must be frequently thrown from their grooves during the manipulation of the tools, by the

side thrust of a wooden lever mounted near the bull wheels. The ropes are crossed between the tug pulley and the bull wheels in order to reverse the direction of the power, and except for the rubbing of the ropes on each other where they cross, and occasional slippage in the grooves in which they run, there is little abrasion. The life of the bull rope is influenced chiefly by the strain put upon it, resulting in direct breakage of the strands and pulling apart of the fibers.

Other cordage used in the derrick is of minor importance, consisting for the most part of hemp rope or light steel wire strand used in supporting the heavy casing tongs, connecting the temper screw with its counterbalance, connecting the "telegraph wheel" with the engine throttle and like purposes.

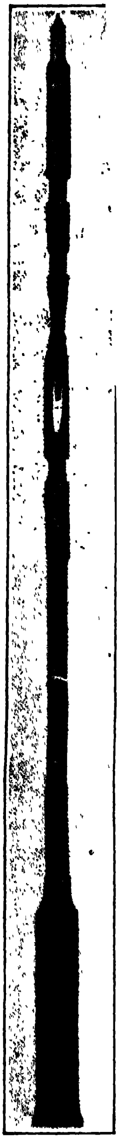


FIG. 45.—The "string" of cable drilling tools.

STRING OF CABLE DRILLING TOOLS

The string of cable drilling tools consists of several parts (see Fig. 45), securely fastened together by tapered screw ("pin") joints. The rope socket which connects the tools with the drilling cable is screwed to the top of a pair of massive telescoping metal links called "jars." These in turn connect at their lower end with a long cylindrical steel "drill stem," and the latter is screwed to the top of the drilling bit. Occasionally a "sinker bar," a short cylindrical steel bar, is inserted between the top link of the jars and the rope socket.[12] The total length of the string of cable tools so connected is usually about 40 ft. The aggregate weight depends upon the size of hole to be drilled, but for a 10-in. hole averages about 3,600 lb.

Cable drilling bits are of several types differing slightly from each other in form and purpose (see Fig. 46). The bit is made of a heavy bar of steel or iron, from 4 to 11 ft. long (commonly 7 or 8 ft.) and somewhat wider than it is thick. It is dressed to a blunt edge on one end and terminates in a tapered "tool joint" at the other. The upper shank of the bit, which is somewhat smaller than the cutting edge, is flattened just below the joint, to facilitate the application of a wrench in screwing it to the drill stem. A wide groove or "water course" is cut down each side of the tool to permit of the easy displacement of the fluid in the well as the tools rise and fall.

The form of the cutting edge is varied to adapt it to the character of the rock formation to be drilled. For hard rocks, a fairly sharp chisel

edge is used, while for soft material the bit will be almost flat on the bottom with only a blunt edge at the center. A chisel-edged bit operating in soft rocks will loosen the material faster than it can be mixed with water, so that the bit rapidly becomes clogged. Particular attention is given, in "dressing" the bits, to shape the edges and corners properly, since the size of the hole drilled and the "clearance" of the bit in the hole, depend largely upon these details. For soft rocks the cutting edge will

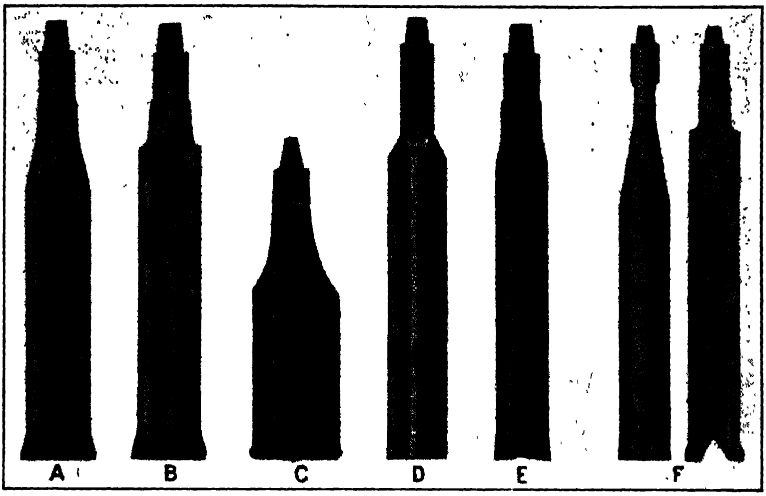


FIG. 46.—Types of churn drilling bits.

A, California pattern; *B*, Mother Hubbard pattern; *C*, spudding bit; *D*, Star bit; *E*, round reamer and *F*, Overman bit.

be dished in somewhat toward the center, so that the corners project slightly. In hard rocks the cutting edge should be almost a straight line, in order to distribute the wear on the bit uniformly and to prevent breakage of the corners.

Several common types of cable tool bits are illustrated in Fig. 46. The "California pattern" represents a widely used type, though the "Mother Hubbard pattern" is preferred by many drillers, particularly in north Texas, on account of its angular form, which, it is claimed, results in the drilling of a straighter hole. The "spudding bit" is a short, broad form used only in starting the well. The "star bit" and "reaming bits" are used for straightening a crooked hole and enlarging the diameter from the top down. The shank of the bit is usually made several inches smaller in diameter than the cutting edge, which permits the bit to work in the hole eccentrically, thus drilling a hole somewhat larger than the actual gage of the bit.

Drilling bits are preferably made of a good grade of tool steel which may be accurately tempered to the proper degree of hardness, and which

holds its cutting edge and resists abrasion. Chrome and other special steels are occasionally used. To reduce the cost, some manufacturers use tool steel only on the lower one-third of the bit, the shank and upper end being composed of a cheaper grade of forged iron or mild steel. This practice is permissible if the weld connecting the two metals can be satisfactorily made. The bits are seldom dressed back in resharpening to more than one-third of their original length before they are discarded, or a new piece of steel is welded on. The metal comprising the upper part of the bit is useful only in adding weight.

Too little attention is given to the proper tempering of drilling bits for best results.[14] The hardness of the rocks to be penetrated should always be considered in tempering the steel. The work of sharpening and tempering the bits is often entrusted to the driller and his "tool dresser," who are frequently not sufficiently skilled in the art of tempering and heat treatment of steel for best results. Furthermore, the equipment provided at the rig for this work is often inadequate. A better practice would seem to be to send the tools to a well-equipped forge shop where they may receive the attention of a skilled tool sharpener.

Difficulty is experienced, especially with the larger sizes of bits, in cracking or breaking of the metal, particularly at the corners and through the thinner metal separating the water courses.[11] This is usually a result of either uneven heating or of using too hard a temper. Large bits should be heated in a very slow fire and frequently turned, special care being taken to avoid overheating of the corners, edges and thinner portions. The metal should be tempered to a straw color on the cutting edge, plunged and allowed to cool slowly with the cutting edge immersed in 1 in. of water or mud. Bits dressed with an uneven cutting edge frequently break at the pins, or in some cases at the wrench squares.

The tool-joints, used in connecting the several parts of the string of cable drilling tools, are equipped with taper screw threads in order to facilitate coupling and uncoupling of the parts (see Fig. 47). They are made of soft annealed steel and are provided with shoulders about 1 in. wide between the threads and the outer circumference of the box. When the shoulders on the two parts of the joint butt together, the friction developed prevents unscrewing as a result of vibration in the well. When the joints are in good condition they can be screwed by hand until they come within about $\frac{1}{16}$ in. of shouldering, after which a wrench operated by a powerful circle jack bolted to the derrick floor must be applied (see Fig. 49). When the joints are new they should be set up by the jack and unscrewed several times before being put into use. They should always be thoroughly clean, free from grease and rust, and the shoulders should be smooth so that they butt properly together. When the threads become cupped as a result of excessive strain put upon them, they should be sent to the shop for rethreading.

For the larger sizes of tools, the joints are usually 4 in. in diameter at the base, and taper to 3 in. at the top. They are cut with 7 threads to the inch, and are known as 3 by 4 in.-7 joints. The threads may be sharp 60°-V threads or they may be flattened as in the U. S. Standard thread. The outer diameter of the metal "box" is usually 6 in. Other

FIG. 47.—Detail of tool joint.

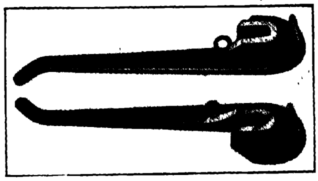


FIG. 48.—Tool wrenches.

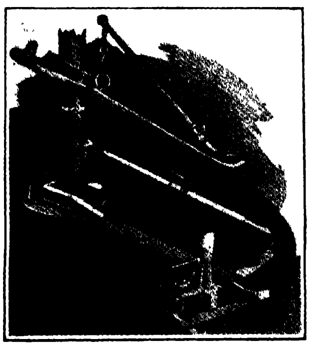


FIG. 49.—Circle jack in position for setting up tool joint.

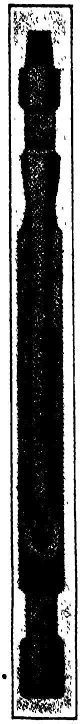


FIG. 50.—Drilling jars.

commonly used sizes of tool joints are 4 by 5 in.—7, 2¾ by 3¾ in.—7, 2 by 3 in.—7 and 1¾ by 2¾ in.—8. The size of the pins must be proportioned to the size and weight of the tools, otherwise the string of tools is apt to pull apart at a tool joint ("jump a pin") during operation in the well. For heavy work in north central Texas it is customary to use a 5½-in. by 30-ft. auger stem equipped with a 4- by 5-in. box and a 3¼- by 4¼-in. pin. The drilling jars used are 6½ in. and are equipped with a 3¼- by 4¼-in. box and pin.[15] In 1922 the American Petroleum Institute adopted the "I and H" joint as standard

for all cable tool joints, except that in California the "H and T" joint may be used until the change can be gradually brought about.

The drill stem, or auger stem, as it is occasionally called, is a cylindrical bar of mild steel or iron equipped with a tool joint and wrench squares at either end. The function of the stem is merely to add weight to the drilling bit. The size varies with the diameter of the hole to be drilled, ranging from 2½ to 6 in. in diameter and from 6 to 42 ft. in length.

The drilling jars resemble two great links of a chain, and are carefully made to slide or telescope on each other (see Fig. 50). The two links are of massive construction, reinforced at the ends where they engage each other, and provided with tool joints at the outer ends. They are of such length that they may telescope for a distance of about 16 in., though "fishing jars" of similar design may have a stroke of as much as 36 in.

The purpose of the jars is to enable the driller to strike a sharp upward blow on the drilling bit, which is frequently necessary in freeing it from clay or shale in which it tends to stick. By adjusting the stroke and the position of the tools in the well, the jars may be allowed to telescope for from 6 to 12 in. on each down stroke. On the up stroke the upper link gathers momentum before it engages the lower, and the tools are suddenly jerked from the sticky material which tends to hold them. In other cases the bit may become wedged in the hole or caving of the walls may necessitate the application of a succession of upward blows before the tools can be freed. The jars are often able to loosen the tools when a direct pull on the drilling cable would be quite ineffective. The jars are not brought into play or can be omitted from the string of tools when drilling in hard rocks.

The sinker bar is similar to the drill stem in form, except that it is shorter. It is used merely to add mass to the weight of the upper link of the jars, thus making the latter more effective in freeing the tools on the up stroke.

The rope socket, which serves to connect the string of tools with the drilling cable, may be one of several types. Those intended for use with hemp cable necessarily differ in form from those used on steel wire cable. The form of the socket should be such that the cable is not subjected to any sharp bends on which it is likely to break, and it should provide a positive grip, strong enough to resist any pull short of that necessary to break the cable. In addition, it must be substantial to withstand the wear and abrasion to which it is subjected, and it should provide a means of conveniently connecting with the drilling tools.

For hemp drilling cables, the New Era socket and the wing socket with rivet fastenings have been widely used (see Fig. 51). In the case of wire rope the strands are usually unwound or loosened slightly at the ends and babbitted in a conical recess provided in the socket. The Babcock socket is the best known example of this type. In the Prosser

socket the cable is held by a pair of cone-shaped slips with serrate teeth which grip it securely when they are drawn up into position. Some drillers consider it an advantage to be able to rotate the drilling

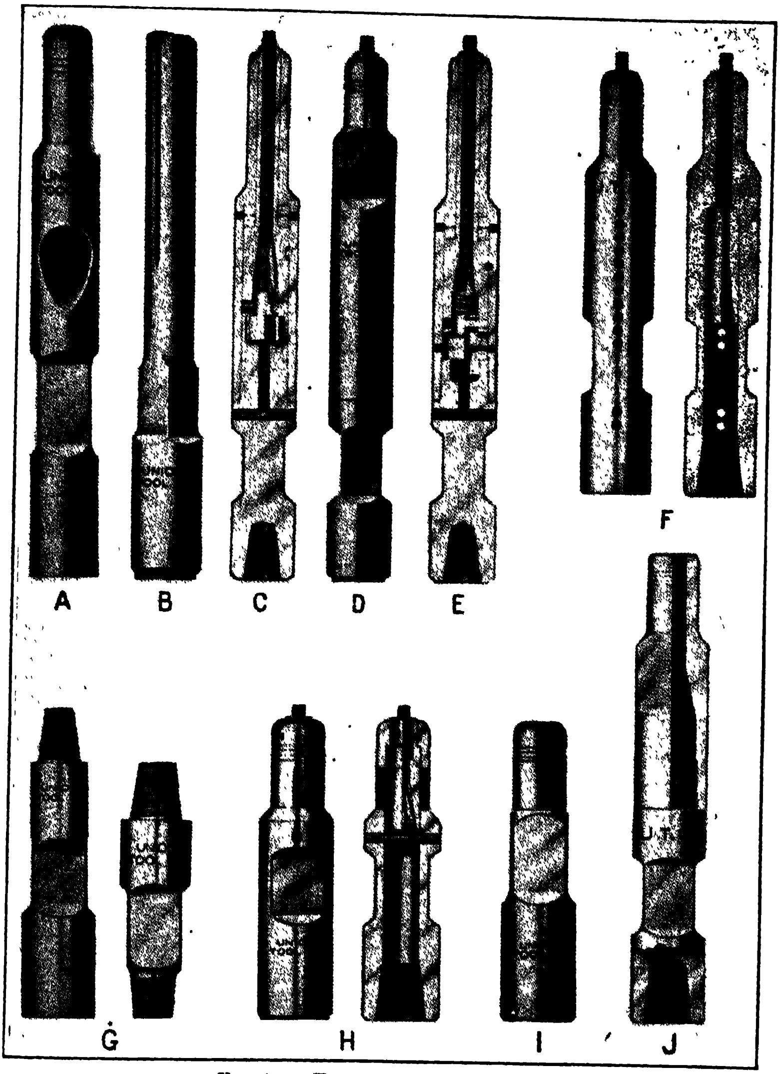


FIG. 51.—Types of rope sockets.

A, New Era socket; *B*, wing socket, *D*, Union rope socket, *C*, ratchet type and *E*, roller-ratchet type; *F*, Prosser socket; *G*, types of substitutes; *H*, double swivel socket; *I*, Babcock socket; and *J*, Babcock manila rope socket.

tools, with the thought that this procedure prevents them from striking repeatedly in the same place, thus avoiding a "flat" hole. While the necessity for this rotation of the tools is doubtful, since they naturally

turn in the hole as the tension in the long cable is alternately applied and withdrawn, some manufacturers have catered to this whim of the driller in the design of ratchet rope sockets which permit of the lower half of the socket turning with respect to the upper half. The Union roller ratchet socket is an example of this type.

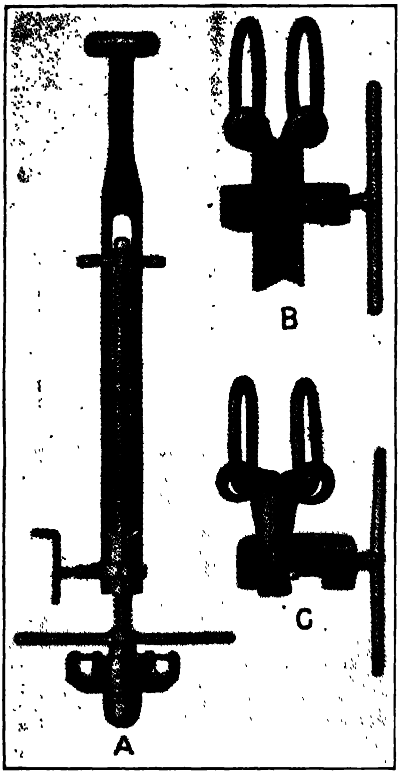


Fig. 52.—Temper screw (*A*) with drilling cable clamps for steel wire cable (*B*) and for manila cable (*C*).

A variety of forms of "substitutes" for connecting the rope socket with tubing or with the many types of fishing tools are available; as well as rope clamps, clips and thimbles used in forming and supporting loops made in the end of a cable.

The temper screw is the device by means of which the drilling cable and tools are suspended from the walking beam, and with the aid of which the tools are gradually lowered so that they continue to strike the bottom of the hole as it is deepened. Fig. 52 shows that it consists of several parts. A substantial metal frame, suspended by a T-bar at its upper end from a slot in the "nose" of the walking beam overhanging the well, supports a split nut between the two reins at the bottom. The two halves of this nut spring slightly apart with the reins in their normal position, but by means of a small elliptical clamp they can be brought together so that their threads engage those of the screw. The screw is from 5 to 8 ft. in length, 2 in. in diameter and cut with a coarse square thread. Attached to the lower end of the screw is a handle by means of which it can be revolved, and a pair of links supporting a clamp which grips the drilling cable. The links pass through holes in a short metal cross-bar or swivel, resting on a shoulder cut on the end of the screw. Frequently, cone or ball bearings will be placed between the cross-bar and the supporting shoulder, so that the screw may be revolved freely without turning the links or rope clamps.

The form of the rope clamps will vary with the kind of drilling cable used. They must be of such shape that they will not damage the drilling cable, and yet they must apply sufficient pressure to prevent it from slipping through. When a manila drilling cable is used, it is custom-

ary to wrap loose strands of old rope about it at the point where it is gripped by the metal clamps. This additional material is so adjusted that it forms a wedge in the upper part of the conical opening in the clamp. For steel drilling cables the clamps consist of two bars of steel with grooves cut through the center to fit the size of the cable being used.

By turning the handle in the lower end of the screw, the latter can be advanced through the split nut until the full length of the screw has passed through. In order to take a new grip on the cable so that drilling can be continued, the weight of the drilling cable and tools must be transferred from the beam to the crown block, and the temper screw loosened on the cable. By loosening the clamp which holds the two halves of the split nut together, the reins spring apart, releasing the nut from the screw which can then be lifted to the top of the frame. The two halves of the nut are then again clamped about the screw, the lower clamps are attached to the drilling cable, the weight of the tools is transferred back to the beam and drilling is resumed.

The weight of the temper screw and all its parts will aggregate from 300 to 500 lb., depending upon the length of the screw and the depth of well for which it is intended to serve. To aid in lifting the screw in the frame, it is usual to attach a rope to its upper end, passing up over the top of the beam and thence down to a balance weight at the side of the Samson post.

The Circle Jack, by means of which the several parts forming the string of cable tools are screwed together, consists of a semi-circular toothed rack which is fastened to the derrick floor around the mouth of the well (see Fig. 49). At one end of the toothed rack a large wrench is held in a stationary position. A second wrench is attached to a traveler containing a ratchet operating on the toothed rack. As the handle is moved backward and forward, the ratchet moves forward one tooth on the rack for each stroke of the handle, thus advancing the movable wrench. In applying the circle jack the tool forming the lower portion of the tool joint is lowered into the well until the wrench square is just level with the derrick floor, and is gripped by the stationary wrench. The wrench square on the upper portion of the joint is then gripped by the movable wrench and the traveler is advanced on the rack until the joint is tight. The joints are generally screwed together as far as is possible by hand, before being lowered into the well and tightened by the circle jack.

Under-reamers.—It frequently happens, especially in drilling through hard rocks, that the drilling tools do not maintain sufficient clearance to permit of free passage of the casing. In such a case an under-reamer may be lowered to the tight place and manipulated in such a way as to enlarge that particular section to the necessary diameter. Under-reamers also find application in reaming out holes at points where free

space about the casing is desired for the introduction of cement in excluding water.

A number of different forms of under-reamers have been designed, and are available from the tool supply companies. Of the various types on the market the Wilson and Swan patterns are perhaps best known (see Fig. 53).

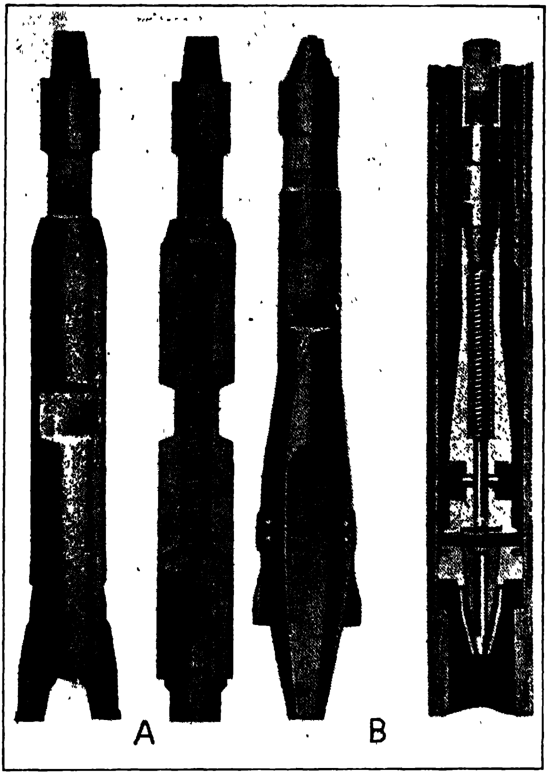


FIG. 53.—Types of under-reamers.
A, "Ideal" under-reamer, Wilson type; *B*, Swan under-reamer.

The under-reamer is equipped with two lugs having specially formed and hardened cutting edges, mounted in the body of the tool in such a way that they expand outward under the influence of a powerful spring. The lugs are held in the collapsed position by a wire or light metal ring, while the tool is being lowered through the well casing, but on emerging from the casing shoe they are forced outward into working position by the spring. With lugs fully expanded some under-reamers are capable of drilling a hole 3 in. larger in diameter than that of the casing through which they pass.

The under-reamer is churned up and down in the same manner as the ordinary drilling bit, gradually enlarging the hole to the limit of expansion

of the lugs. On withdrawing the under-reamer from the well, the lugs are compressed into the body of the tool against the pressure of the spring, as they enter the casing shoe. The moderate side pressure of the lugs against the inner walls of the casing introduces slight resistance to withdrawal of the tool.

In operation, the brunt of the contact with the rock walls of the well falls directly upon the cutting edges of the lugs, which are consequently rapidly dulled. Care should be taken in dressing the lugs to give them a hard temper in order that they may better resist abrasion. If the steel is too hard, however, the edges become brittle so that they break in service. Some operators find that a little hard cast iron melted on the cutting edges of the lugs with an oxyacetylene torch, greatly increases their useful life. Under-reamer lugs are frequently made of chrome or manganese steel which are tougher and more resistant to abrasion than ordinary tool steel. The lugs are forged on special anvils or dressing blocks, recessed to conform with their peculiar shape.

Bailers, used in removing from the well the pulverized rock loosened by the bit during the process of drilling, are constructed of a pipe of suitable size in the lower end of which is fastened a reinforcing shoe and valve. At the upper end a bail is provided for attaching the sand line. Short bailers may be used when the well is shallow and large in diameter, but for great depths, and where the diameter of the well is small, the length must be increased to as much as 20 or 30 ft., occasionally even 40 ft., in order to handle a greater quantity of material with each trip of the bailer to the bottom.

Bailer valves are of two types. The disc valve is hinged at one side, opening upward (see Fig. 54). The dart valve is spherical or ovoidal in form and has attached to it, on its lower side, a metal stem or dart which passes through the circular valve seat and projects beyond the lower end of the supporting shoe. In the case of either type of valve, upward pressure of the well fluid on the descending bailer raises the valve so that the fluid passes through until it rests upon the bottom of the well. The bailer is then raised and dropped a few feet ("spudded"), the process being repeated several times in order to force as much as possible of the sand and clay through the valve. On hoisting the bailer, downward pressure at once closes the valve so that even though the top is open, no fluid is displaced. On emerging from the well, the bailer is dumped—in the case of a bailer equipped with a dart valve, by lowering it into a wooden trough, the upward pressure of the trough bottom on the dart lifting the valve from its seat, thus permitting the contents of the bailer to flow out. In dumping a bailer equipped with a disc valve, it is lowered over an upright metal pin mounted in the trough, which lifts the valve on its hinge.

The main body of the bailer is often made of well casing 2 or 3 in. smaller in diameter than the casing through which it must operate. Occasionally a spirally riveted sheet metal pipe will be used for light service. If a long bailer is needed and more than one joint of pipe must be used, two or more sections may be connected, end to end, with swedged or flush-riveted joints. The bail and reinforcing shoe are also riveted in position on the ends of the pipe. The reinforcing shoe is of cast steel and is provided to prevent wear and distortion of the lower end of the bailer, which is subjected to considerable abrasion during the process of lowering and spudding it in the well.

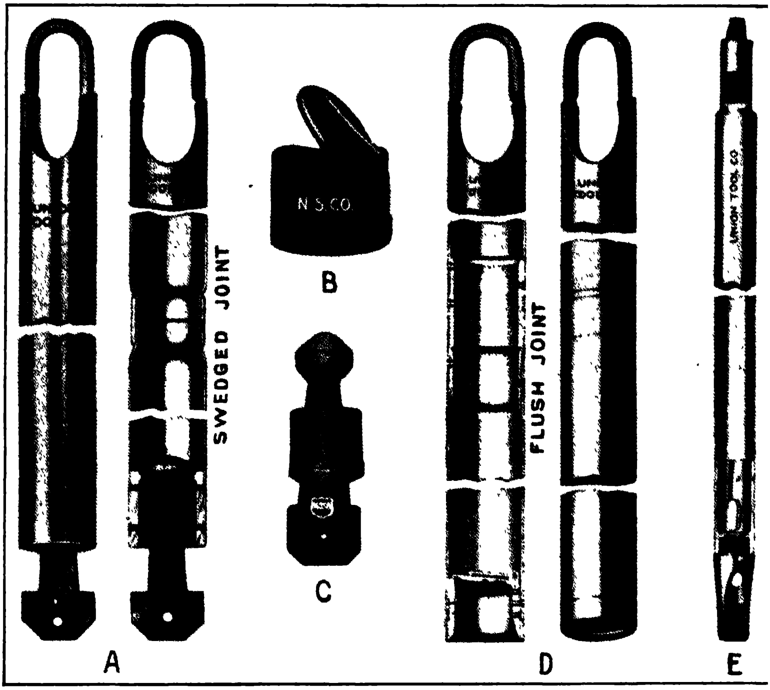


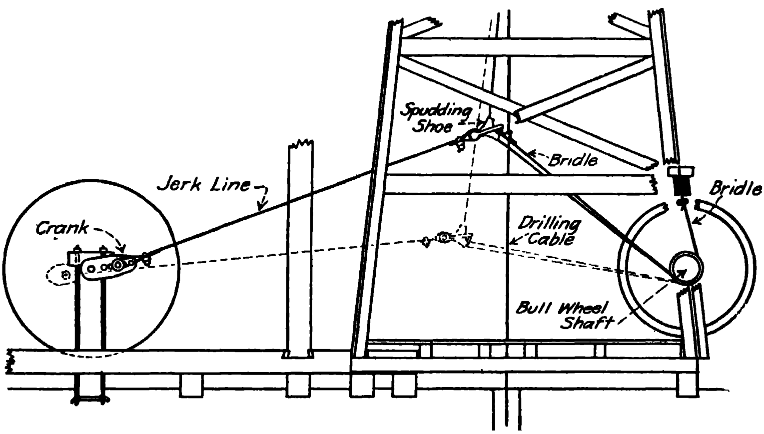
FIG. 54.—Types of bailers.

A, dart valve bailer, *B*, disc valve; *C*, dart valve; *D*, disc valve bailer and *E*, combination bit and mud socket.

Sand Pumps.—If the fragments of rock loosened by the drill are coarse, they settle rapidly to the bottom and it will be difficult to get them into the ordinary type of bailer. For such conditions it is customary to make use of a "sand pump," which is similar to an ordinary bailer in general construction and form except that it is provided with a piston or plunger which can be moved up and down in the cylindrical shell to create suction helpful in drawing coarse material past the valve. In one type of sand pump the sand line is attached to the top of a plunger rod instead of to the bail. A slot in this rod, straddling the bail, permits

of the piston being raised a number of feet as the sand line is hoisted, before the plunger engages the bail and lifts the main body of the pump.

Mud Sockets.—When soft clay or mud must be penetrated by the well, or when such materials have had time to settle into a solid mass in the bottom of the well, the bailer is not always effective in removing them. They can be easily penetrated by the drill, but settle rapidly before the tools can be withdrawn and the bailer lowered. In such cases a "mud socket" (see Fig. 54) may be substituted for the drilling bit on the bottom of the string of cable tools. This device consists of a heavy metal tube equipped with a beveled reinforcing shoe and inclined disc valve within the lower end. It is churned up and down within the well until full of mud or clay, when it is withdrawn for cleaning. For work in very stiff muds or clays the socket is sometimes also provided with a sharp chisel-edged bit attached to the shoe in such a way that it does not interfere with the passage of material through the valve.



(After W. H. Jeffery, with additions)

FIG. 55.—Illustrating method of spudding.

DRILLING WITH THE CABLE TOOLS

Spudding.—Since the complete string of cable tools is 40 ft. long or more, there is not sufficient head room to conduct drilling operations with the aid of the walking beam until a depth of at least 60 ft. is attained. The first 60 ft.—frequently several hundred feet—of the well is therefore drilled by a process known as "spudding," which does not involve the use of the beam. A special spudding bit is used which is shorter than the usual pattern, and a short stem without jars. The drilling bit is lowered to the bottom of the cellar inside of the conductor, a little slack is allowed in the cable, and the bull wheels are securely locked with the brake. A spudding shoe is then placed on the drilling cable a short distance above the bull wheel shaft, and a jerk line connecting with the wristpin on the

crank is attached to the clevis of the shoe (see Fig. 55). With each revolution of the crankshaft, the tools are lifted a short distance and dropped on bottom. By occasionally releasing the bull wheel brake and letting out more of the drilling cable, the tools may be kept striking on bottom. Progress is often slow by this method, but deficiencies of the method are usually offset to some extent by the soft character of the surface strata. Operation of the drilling tools must, of course, be occasionally interrupted to bail out the material loosened by the drill. It is preferable to use a manila drilling cable during the spudding process, since the action with a steel cable is somewhat detrimental to the rig, particularly if the rig is a light one.

"Hitching On."—When sufficient depth has been attained to permit of operating the full string of tools with the walking beam, the spudding equipment is removed, the temper screw is adjusted in position on the end of the beam and the complete string of tools with a regular pattern drilling bit is assembled. Care is taken, as the tools are lowered past the derrick floor, to set up each tool joint with the circle jack to make certain that all are tight. The tools are lowered by partially releasing the bull wheel brake until bottom is reached. When lowering the tools into the well, the driller applies the bull wheel brake at intervals of a few feet when nearing the bottom in order to stop the descent just as the tools reach bottom on the full stretch of the cable. In drilling, the tools should strike bottom while the cable is extended to the limit of its elasticity, thus insuring the maximum rebound. This elastic rebound probably increases the effective stroke of the tools by several feet under favorable conditions, and is also effective in promptly freeing the bit from clay or loose material in the bottom of the hole, and in keeping the cuttings in suspension in the well fluid.

With the tools suspended from the crown pulley in the proper position, as determined by "springing" the line as described above, the engine end of the walking beam is raised and the pittman attached to the crank, with the wristpin in the third or fourth hole and with the crank at the top of its arc. With the temper screw gripped in the highest position in its frame, the temper screw clamps are then firmly attached to the drilling cable, the bull wheel brake is released and sufficient slack cable is pulled over the crown pulley to prevent jerking of the cable above the walking beam as the latter oscillates. The weight of the tools is thus transferred from the crown pulley to the walking beam, and as soon as the engine has been centered, all is in readiness for drilling.

The Mechanics of Drilling with the Cable Tools.—The engine is started, and a the beam oscillates, the driller, with his hand on the drilling cable, notes the vibration or "jar" which, to the skilled observer, indicates the manner in which the tools are operating. Slight adjustments in the position of the temper screw or in the speed of the engine are made, until the tools are striking with the maximum force on the bottom of the hole.

Satisfactory progress depends to a large extent upon the ability of the driller to interpret the vibrations that come to him through the drilling cable. The novice sometimes "loses the jar" and works for hours without making any progress. The tools may be standing on bottom while he is playing with the slack in the cable, or they may be swinging several feet off bottom. The skilled driller will know as soon as his hand touches the drilling cable whether the drill is working properly or not.[12]

The jar which the driller feels in the cable is the result of alternate release and application of tension in the drilling cable as the beam rises and falls. Because of the elasticity of the cable, it is probable that the beam is already returning on the up stroke as the tools strike bottom, the result being a distinct jar in the cable as the tools rebound, usually of sufficient intensity to cause vibration of the rig. In addition to the jar, to the sensitive hand of the driller on the cable there is a perceptible "reach" and "lift" of the cable as tension is applied and released. As explained above, the tools strike bottom with the cable under tension, the amount of tension depending upon the elasticity of the cable and the extent to which the tools have to reach for bottom. When the tools strike and rebound, the same elasticity causes a contraction of the line, giving the sensation of lift. The action of the tools may be compared with the bounding movement of a small weight churning up and down while suspended on the end of a rubber band. The tools reach down on the stretch of the line and strike a springing blow, rebounding rapidly. As the tools begin to reach for bottom and the "jar works off," the driller "tempers the jar" by lowering the tools with the temper screw.[5]

The speed of the engine and length of stroke of the beam have much to do with the action of the tools. As the well attains greater depth, it is necessary to lengthen the stroke by moving the wristpin further from the center of rotation of the crank. For a given length of cable and of stroke, there is a certain periodicity which determines the speed at which the engine should operate. Overspeeding of the engine will result in jerking the tools upward before they strike, subjecting the cable and tools to a destructive strain which often causes breakage of the jars or parting of the drilling cable. Such action of the tools also induces a jerky motion in the engine, until it becomes unmanageable. Catching the tools in this way is one of the common difficulties of the unskilled driller. Too slow a motion, on the other hand, will greatly reduce the force of the blow struck by the tools.

Power control becomes increasingly difficult as greater depths are attained. This is a direct result of the greater weight of cable to be lifted and the greater elasticity of the longer cable. This loss of effectiveness of the engine is offset to some extent by lengthening the stroke, or by use of the engine balances on the rim of the flywheel. With an ordinary drilling engine, great skill in steam control is necessary to operate the tools effectively at depths in excess of 2,000 or 2,500 ft. without the use of engine balances. Satisfactory operation of the engine requires a slightly greater speed on the down stroke of the tools than on the up stroke. This results naturally from the alternate release and application of the load on the engine. When balances are used on the engine flywheel, however, a more uniform speed results, which to some extent retards the drop of the tools and compels a slower motion. Hence the use of the engine balances should be avoided until made necessary by the jerky action of the engine.[5]

The action of the tools will vary with the kind of cable used. Hemp cable has greater elasticity than steel, and will reach for and strike bottom long after the steel cable under similar conditions will have ceased to strike. The steel cable, when unduly stretched, will often "peg-leg," that is, the tools will alternately strike bottom and miss. Hemp cable has more lift than steel, a characteristic which, as we have seen, depends upon the elasticity of the cable. Both lift and peg-legging are to a

great extent dependent upon depth. The remedy is an extension of the temper screw. The action of the tools will also vary somewhat with the amount of water in the hole. Water, of course, retards or dampens the motion of the tools, its effect being particularly noticeable in drilling "wet" holes with hemp cable of large diameter. Drilling with the hemp cable requires greater skill on the part of the driller than when steel cable is used.

Opportunity was afforded for observing the effect of elasticity in the drilling cable in one instance where a churn drill hole intersected underground mine workings at a depth of 500 ft. A hemp cable was used with a 36-in. stroke at the walking beam, but at a depth of 500 ft. the actual length of stroke of the tools was in excess of 8 ft. The elastic rebound of the tools also varies markedly with the character of the rock in which the bit is working, being appreciably greater in hard rocks than in semi-plastic clays and shales. Because of the reach of the cable in drilling, it is probable that in most cases the hole is actually several feet deeper than the normal length of the drilling cable and tools.

With some types of rocks, best results are obtained by operating the tools "tight hitched," that is, allowing them to strike only on the extreme elastic stretch of the cable. In other cases, "loose hitching" gives best results. The tools should always be tight hitched when drilling through hard, steeply inclined strata, because of the tendency of the bit to follow the dip of the strata, thus drilling a crooked hole.

The impact of the heavy cable tools on the bottom of the well when the tools are dropping freely, is enormous. Let us assume that a 10-in. hole is being drilled. The weight of the tools will probably aggregate about 3,600 lb. for this size of hole. The length of stroke or sweep of the walking beam will be, say, 3 ft. Add to this the stretch or spring in 2,000 or 3,000 ft. of drilling cable, and we have a total drop for the tools of perhaps 5 or 6 ft. Multiplying the lower figure by the weight of the drilling tools (3,600 lb.), we obtain 18,000 ft.-lb. of work exerted on the formation at each stroke. When it is considered that this impact is repeated at the rate of perhaps 30 strokes per minute, on an area of not more than three-tenths of a square foot (approximate area of the end of a 10-in. bit), it is apparent that we have to deal with a crushing force of considerable magnitude.

Because of the shape of the end of the bit, and the absence of a sharp cutting edge, it is probable that there is comparatively little actual chipping or cutting of the rock, but rather a crushing action which breaks down the rock mass into small fragments. The shape of the disintegrated material will vary with the nature of the rock, being granular in the case of sandstones and amorphous rocks, and platy in the case of thin laminated strata and in rocks possessing well-developed cleavage. The material brought to the surface in the bailer is generally finely pulverized by repeated pounding of the bit on the larger fragments after they are detached from the main rock mass. The walls of the well are probably left rather rough as a result of the action of the bit, and the material in the walls will be badly fractured except in the case of very hard, tough rocks. Because of this, in soft formations the walls tend to cave. The walls are sustained to some extent, however, by the action of clay which accumulates from the sludge between the rough projections on the walls, plastering over the fractures and preventing further disintegration to some extent.

Drilling with the Jars.—In drilling through beds of sticky clay or in caving formations, it is often necessary to bring the jars into play in order to effect release of the bit on the up stroke of the tools. Drilling jars are attached above the stem and usually have a stroke varying from 4½ to 12 in. In drilling, the jars are only permitted telescope for a part of their maximum stroke, say, for 4 or 6 in.[3] This displacement permits the upper link to gain considerable momentum on the up stroke before picking up the bit and stem. Such action provides the necessary sudden upward jerk to free the bit from sticky material in the bottom. A skillful driller never allows the jars

to strike on the down stroke except in certain fishing operations when a jar-down effect is desired.

Rotating the Tools.—In certain kinds of rock, the cable tools have a tendency to drill a flat hole; that is, the well becomes elliptical in cross-section. This can only result from the bit striking repeatedly in one position. Since the bit is wider than it is thick, such action is inevitable unless the bit revolves as it operates. Formerly, drillers considered it necessary to twist the cable slowly at the temper screw as the tools churned up and down in the well, but the efficacy of this practice is questionable in view of the great length of cable that often exists between the temper screw and the tools. Many drillers insist on the use of a ratchet or swivel type of rope socket, which is supposed to permit of easier rotation of the tools and permits twists in the drilling cable to readjust themselves independently of the tools. A recent innovation is the use of the spiral-winged drill stem to aid in securing positive rotation of the tools as they rise and fall through the well fluid. It seems reasonable to expect that the spinning of the tools induced by alternate application and release of tension in the cable would be sufficient to prevent the tools from striking repeatedly in the same position, except, perhaps, at very shallow depths. If the tools fail to rotate, it is probably due in most cases to loose material accumulating on the bit or on two opposite sides of the hole, and more frequent bailing or a more rapid motion of the tools should remedy the matter.

Flat holes are particularly likely to occur when drilling through water sands. "Tight" holes, which result from loss of gage by wear on the sides and corners of the bit, are also characteristic of such material, and for this reason water sands are generally under-reamed. The bits should be frequently redressed if proper clearance for the casing is to be maintained.

Bailing.—Continued operation of the drilling tools results in accumulation of cuttings in the bottom of the well, which will eventually so restrict the motion of the tools that little or no progress is made. Such a condition requires removal of the drilling tools and operation of the bailer.

To "draw out the tools," the bull wheels are first revolved by hand until the slack cable over the crown pulley has been wound on the bull wheel shaft. The bull ropes are then thrown on, causing the wheels to revolve under the influence of the power, and hoisting the tools in the well until the load is transferred from the temper screw to the crown pulley. The driller then promptly throws off the bull ropes and clamps the bull wheel brake while his helper stops the engine. While this is being accomplished, both the walking beam and the bull wheels are in motion, and unless the power is disengaged at the proper time, damage to the rig will result.

The temper screw clamps are then removed from the drilling cable, and the pittman is taken off the wristpin and lowered to the plank walk. This elevates the end of the beam overhanging the well and places it out of the way of the drilling tools and bailer as they are run into and out of the well. The bull ropes are now again placed in position on the bull wheels and power is applied, raising the tools until they emerge above the derrick floor; the bull ropes are then thrown off and the tools are caught and suspended above the well by clamping the bull wheel brake until they can be swung over into one corner of the derrick.

Manipulation of the sand reel reach draws the friction pulley forward against the face of the band wheel, thus causing the sand reel to revolve, and lifting the bailer until it swings freely above the derrick floor. Reversing the position of the reach causes the friction pulley to bear against its brake post so that the bailer can be held suspended in any desired position. The lower end of the bailer is guided into the well, the brake is released and the bailer is allowed to descend rapidly, braking occasionally, until bottom is approached, when the descent is brought under close control by further application of the brake.

The bailer is raised a few feet and lowered to bottom several times to make certain that coarse material accumulated near the bottom has had ample opportunity to pass the bailer valve. It is then withdrawn as rapidly as possible, by bringing the sand reel friction pulley to bear against the face of the revolving band wheel. On reaching the surface, the bailer is suspended with the lower end a little above the derrick floor, by shutting off the power and applying the brake. The loaded bailer is then swung to one side from its position over the well and lowered (by partially releasing the brake) through a hole in the derrick floor into a wooden trough placed immediately beneath. As the bailer valve is raised by downward pressure of the dart on the bottom of the trough (or by a metal rod mounted vertically in the trough in the case of a disc valve bailer), the contents of the bailer flows out and may be inspected to determine the nature of the material. The power is then applied, rais-

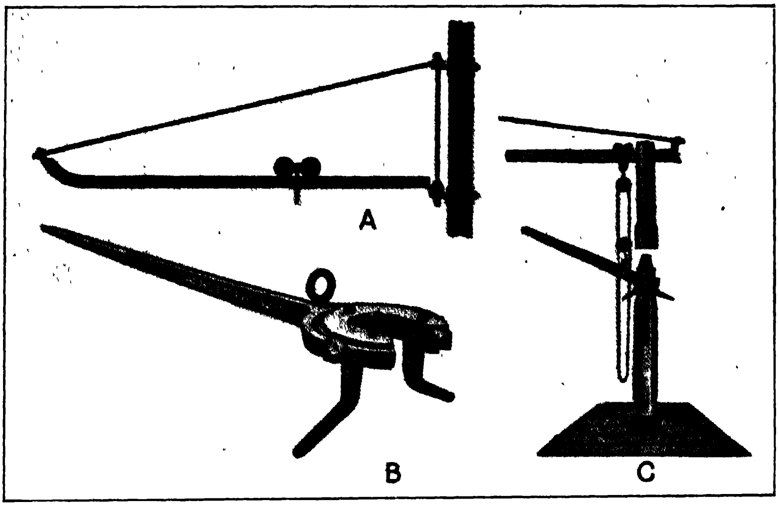


FIG. 56.—Derrick crane (*A*) and swivel wrench (*B*) for supporting drilling bit (*C*).

ing the bailer until it clears the derrick floor, when it may be swung over into one corner of the derrick and held out of the way by a metal hook or rope sling, or it may be lowered into the well for another load of sludge. Usually several trips to bottom with the bailer will be necessary before the well will be sufficiently cleared to resume drilling operations. The process of lowering the tools and attaching the temper screw as described above, must then be repeated.

Replacing a Worn Bit.—Continued use dulls the cutting edge and corners of the bit and reduces its gage so that it no longer drills a hole of the desired diameter. It must therefore be occasionally replaced with a properly dressed and gaged bit. When slow progress warns that the bit has become dull, the tools are drawn out as described above under "Bailing." As the tool joint between the drill stem and the bit emerges from the well above the derrick floor, the power is shut off and the tools held suspended (with the bit in the well) by clamping the bull wheel brake. The tool joint is loosened by application of the circle jack and the power again applied until the bit swings free above the derrick floor. The bit is then unscrewed from the stem, with the aid of hand wrenches if necessary, and a fresh bit is screwed to the stem in its place. The heavy bits are conveniently supported before attaching to and after disengaging from the stem, by means of a swivel wrench hung horizontally, suspended on chain blocks from a derrick crane (see Fig. 56). Such a crane can be

swung to any desired position over a radius of 10 ft. from the post in one corner of the derrick to which it is attached. The wrench, supported on its chain hoist is suspended from a small 2-wheeled trolley which may be moved to any desired position along the horizontal beam of the crane. On lowering the sharpened bit into the well, the tool jóint connecting it with the stem is "set up" with the aid of the circle jack.

The Routine of Drilling with the Cable Tools.—Unless some accident occurs to interfere with the operation of the tools, the routine of the work becomes rather monotonous. The equipment is usually operated day and night, with either 2 or 3 crews of men working 12 or 8 hr. respectively. Each crew consists of two men, the driller, who is in responsible charge of the work, and his helper or tool dresser. The work is divided into alternate periods of drilling and bailing, with occasional interruptions to insert casing (see Chap. VII).

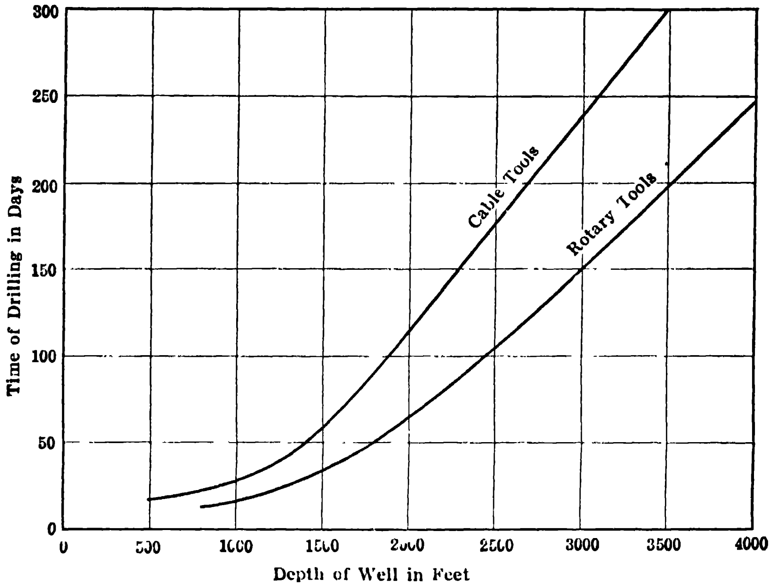
The frequency of bailing depends upon the nature of the material in which the drill is working. Frequency of bailing also depends upon the rate of progress and the extent to which the material loosened by the bit remains in suspension in the well fluid. Certain kinds of clays and soft clay shales require frequent bailing, perhaps for every 2 or 3 ft. of progress. In hard rocks on the other hand, the hole may be advanced for several lengths of the temper screw without necessity for bailing.

If it is unnecessary to bail when the full length of the temper screw has been let out, the engine is stopped and the weight of the tools is transferred to the crown blocks (as described under "Bailing"), while the temper screw clamps are loosened from the cable and the screw is raised for a new grip on the cable. The clamps are then attached in the new position, the weight is transferred back to the beam (as described under "Hitching On") and drilling is resumed. The temper screw can ordinarily be extended about 5 or 6 ft., so that the procedure outlined for taking a new hold on the cable need only be repeated at this interval.

Unless water enters the well from the formations penetrated, sufficient must be poured in at the surface to form a thin sludge with the material loosened by the drill. Practice differs in the depth of fluid maintained in the well. In dry-hole drilling, as commonly practiced in the fields of the eastern United States and in some of the mid-continent, Texas and Rocky Mountain fields, only sufficient water is used to keep the drill cuttings from clogging the bit; but in some of the California fields the hole will be maintained full or nearly full of water, to aid in preventing the walls from caving. Dry-hole drilling is preferable since the tools develop their maximum efficiency when movement is not impaired by friction of the drilling cable on a long column of water, and by the bouyant effect on the tools; but where the walls have a tendency to cave, or where "heaving" formations are to be penetrated, the pressure of a long column of water is of considerable assistance. Long strings of heavy casing may also be more readily handled in a hole full of water.

The Speed of Drilling.—The number of strokes per minute at which the drill can be operated will depend upon the depth of the well, the diameter, the depth of fluid in it and the nature of the material in which the bit is working. Generally speaking, greater depth, smaller diameter, greater depth of fluid and soft material necessitate a slower motion. The number of strokes per minute will ordinarily range between 20 and 40.

The rate of progress in cable drilling will vary within wide limits. Varying character of the formations penetrated, the depth of the well, its



(*After M. L. Requa, with additions*).

FIG. 57.—Graphs showing average rate of progress in cable and rotary drilling, California fields.

diameter and time lost in inserting casing and cement and in fishing operations, are important variables that influence the rate of progress. In soft rocks at shallow depths, under favorable conditions, an advance of 100 ft. or more may be made in a 24-hr. day. In a hard layer of "shell" (any hard rock), 5 ft. of hole may represent a good day's work. The rate of progress also depends largely upon whether or not the walls stand without caving and whether the material penetrated tends to heave or flow into the well. The depth of the well influences the rate of progress in two ways: the tools do not work as satisfactorily and must be operated at a slower speed, and more time is consumed in drawing out and lowering the tools and bailer. The tools do not drop as freely in a hole of small diameter, particularly if it is filled with water. Hence a slower drilling speed must be adopted and progress is slower. Any interruption in the

usual routine of drilling of course greatly influences the average footage drilled per day. Casing may have to be under-reamed or driven past tight places in the hole. Breakage of the tools or parting and collapsing of the casing may necessitate a "fishing job" of several days' or even weeks' duration, during which no increase in depth is attained. When cement is introduced into the well to exclude water, an interval of at least several days is allowed for the cement to set and harden before drilling is resumed.

In the San Joaquin Valley fields of California, a region characterized by comparatively soft formations, up to moderate depths (say 1,500 ft.), progress will average about 30 ft. per day, with a maximum of 60 to 70 ft. and a minimum of 5 ft. At depths in excess of 3,000 ft. in the same region, 15 ft. per day is a good average rate of progress, with about the same minimum and a maximum of, say, 30 or 40 ft. In a 1,350-ft. hole drilled in the black shales and lime of north central Texas—an unusually hard formation—progress averaged 27 ft. per day, a high average for this kind of rock. The graphs reproduced in Fig. 57 indicate average rates of drilling for both cable and rotary tools in the San Joaquin Valley region of California where both methods of drilling have been extensively used under conditions that permit of making close comparison of actual performance. It will be noted that the rotary tools make better progress except at very shallow depths.

Identifying Formations and Gathering Log Data with the Cable Tool Equipment.—The cable tool driller is able to identify the kind of rock in which the drill is operating by the rate of progress, by the jar on the drilling cable and by the wear on the drilling tools.[8] Cuttings brought up by the bailer, when thoroughly washed to free them of mud, provide a means of accurately identifying the nature and mineral content of the rock. Usually, too, a little of the material in the bottom clings to the drilling bit as it is withdrawn. Table XII indicates the mechanical reactions and character of the cuttings obtained from different types of sedimentary rocks. The material brought up by the bailer is mostly mud, but by carefully stirring and washing a little of it in a bucket, the coarser material may be segregated and examined.

Depth to bottom is determined at any time, either by actual tape measurement, by measurement of the drilling cable or sand line or by recording the length of casing in the well, if the casing extends to bottom. For shallow wells, a heavily weighted steel wire tape coiled on a reel mounted at one side of the well, may be lowered to bottom and the depth measured directly. In deep wells the magnetic drag of the tape on the casing is frequently so great that it is impossible to tell when the weight reaches bottom, or to feel the "pick-up" as the weight is lifted off bottom. Measurement on the drilling cable or sand line is probably more accurate

TABLE XII.—MECHANICAL REACTIONS ON CABLE TOOL DRILLING EQUIPMENT AND CHARACTER OF CUTTINGS OBTAINED FROM DIFFERENT TYPES OF SEDIMENTARY ROCKS*

Field and formation	Mechanical reactions	Cuttings	Effect on bit
Southern Oklahoma:			
Shale	Tools run smoothly and drill easily and fast in dry hole.	Bailer material mostly mud; fragments in mud and occasionally on bit.	Does not wear bit.
Gumbo	Drills roughly; tools jerk walking beam and do not drop freely.	Bailer material mud; tools come out loaded with gumbo.	Does not wear bit.
Soft sand	Drills fast and easily; tools plunge.	Sand in bailer; none on bit.	No wear on bit, but markings vertical.
Sandstone	Drills smoothly with occasional "kick back."	Grains of sand and chunks of sandstone in bailer.	Wears bit out of gage.
Limestone	Hard and slow drilling; big "kick back."	Chips and irregular pieces, rock mostly pulverized.	Wears bit, but does not cause to lose gage like sandstone
Gypsum	Drills smoothly and more easily than crystalline limestone.	Mostly pulverized; occasional flakes.	Does not wear bit excessively.
Ranger field, Texas:			
White limestone	Drills hard but free, with tight line.	White and pulverized.	Cuts bit badly—3 bits per tour.
Shale	Drills fast and easily in dry hole.	Chunks and fragments in bailer and small pieces stuck to bit.	Does not cut bit.
Black limestone	Drills hard, with tight line through oil saver.	Cuttings fine grained.	Cuts bit a little.
Wyoming field:			
Hard shell	Drills clean with increased motion.	Occasional fragments in bailer.	Does not wear bit rapidly; cuts it vertically like sand.
Limestone	Drills clean with increased motion.	Cuttings fine grained and heavy.	Does not wear bit badly.
Shale, slate, etc.	Drills fast in dry hole, except when cavy. Slow motion.	Fragments of material in bailer.	Very little wear, but "dubs bit under."
Sandstone	Drills clean and free.	Cuttings show as sand grains and fragments of cemented grains.	Cuts bit badly, vertically.

* After R. E. COLLOM in U. S. Bureau of Mines, *Bull.* 201.

if carefully done. For this purpose, the distance from the derrick floor over the crown and down to the upper flange of the sand reel, or to a point on the bull wheel shaft 5 ft. above the derrick floor, is carefully determined by tape measurement, and one or the other of these units is applied on the sand line or drilling cable respectively, as described on page 293. Measurements are made while drawing the bailer or tools out of the hole, care being taken to record bottom on the pick-up that is, just as the sand line or cable receives the full weight of the bailer or tools on leaving bottom. If depths are determined by the casing record, an accurate measurement of all casing in the hole must be kept, lengths

being measured from top to top of collars after the joints are securely screwed together.

The driller usually maintains a "target" or reference mark on the sand line or drilling cable, indicating the approximate depth to bottom, depths in excess of the reference mark being measured with the aid of a steel tape or a 5-ft. "stick" which is a part of the equipment of every cable drilling rig. Examination of well logs will show that many drillers do not attempt measurements within the 5-ft. length of the stick. Measurements involving lengths in excess of 100 or 200 ft. should not be attempted with the stick because of the inaccuracies involved. Measurement with the steel tape is always preferable. Usually the driller knows the depth to bottom at the beginning of each "screw," and when a change in formation is noted by the action of the drilling cable he has only to measure the length of temper screw paid out to record the depth at which the new formation was encountered.

PORTABLE AND SEMI-PORTABLE RIGS FOR CABLE DRILLING

For prospecting work, and for drilling wells in shallow territory—even up to depths of 2,500 ft.—portable and semi-portable drilling machines are often used.[17] These are much lighter than the standard cable rig described in the foregoing pages, but operate on the same principle and often by quite similar equipment. Instead of a derrick, these portable rigs are generally equipped with a braced mast, and the machinery is mounted on a 4-wheeled truck or on a light timber frame structure that can be readily moved about as a unit from one location to another and put in condition for active service within a few hours' time. The trucks are sometimes of the self-tractor type so that they can be moved about under their own power.

Each part of the standard cable rig has its counterpart in most of these portable rigs, often changed in form and size, however, to adapt it to use in a smaller space and to render it more readily transportable. There is necessarily some form of a walking beam or spudding device to impart the churning motion to the drilling cable. There must be two hoisting drums on which the drilling cable and sand line are wound, and there must be a source of power with means of distributing it to the different parts of the rig. Some of the heavier rigs are equipped with an additional drum for handling casing. Usually, however, the drilling cable is used for handling casing. A steam engine and boiler furnish the power in most cases, though occasionally a gasoline engine will be used. The latter type of engine is simpler as a power unit, and occupies less space, but is not as well adapted to the work of drilling as the steam engine. The drilling tools and incidental equipment are quite similar to those used in connection with the standard cable outfit, except that they are usually smaller and lighter.

Probably the greatest difference to be noted in the several types of portable and semi-portable rigs is found in the design of the mast. The mast serves the same purpose as the derrick, and must therefore provide a support at a suitable elevation for the sheaves used in changing the direction of the drilling cable, sand line and casing line. Two types of masts are in common use: first, the single-post mast, which consists of a single heavy timber mounted on end on the ground or on one end of the truck on which the machine is mounted; and second, the two-legged braced mast, built of metal channels latticed together, or of two heavy timbers, suitably braced by horizontal girts and mounted on the sides of the truck. In some cases the mast is entirely independent of the drilling mechanism. It is often built in sections to facilitate transportation, the sections being readily assembled and disassembled. The braced mast can be built of lighter material than a single-post mast of the same strength, and if properly designed should be more rigid. In either case the mast is slightly inclined from the vertical to bring the sheaves at the top clear of the supports, and must be braced with guy wires in several directions to near-by stakes driven in the ground.

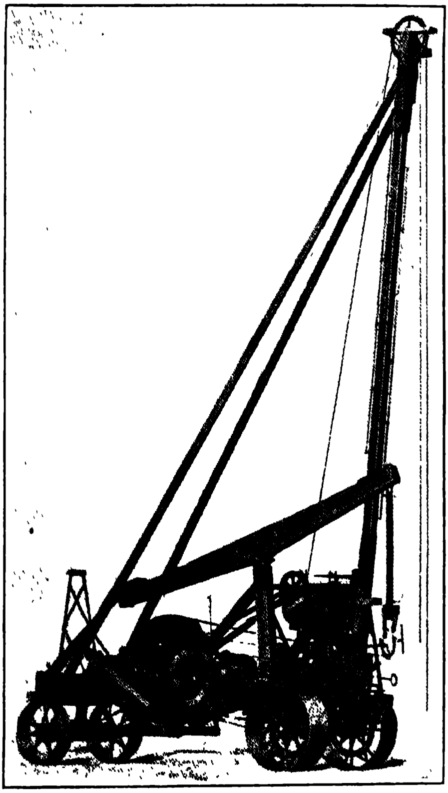
Of the many drilling machines in use, the Star and Columbia drilling machines are probably best known in the group of portable machines, while the National rig is the best known of the semi-portable type. A brief description of each of these machines will serve to acquaint the reader with the main features of portable and semi-portable drilling equipment. The reader is referred to the manufacturers' catalogs for more detailed information on these and other machines.

The Star portable drilling machine is made in a variety of sizes, all mounted on 4-wheeled trucks, the heaviest model (No. 30) being rated by the manufacturers for drilling to depths as great as 4,000 ft. The heavier models are all equipped with vertical reversible steam engines and boilers, but several models equipped with gasoline engines are also available for drilling to depths of less than 1,000 ft. The latter are of the self-tractor type.

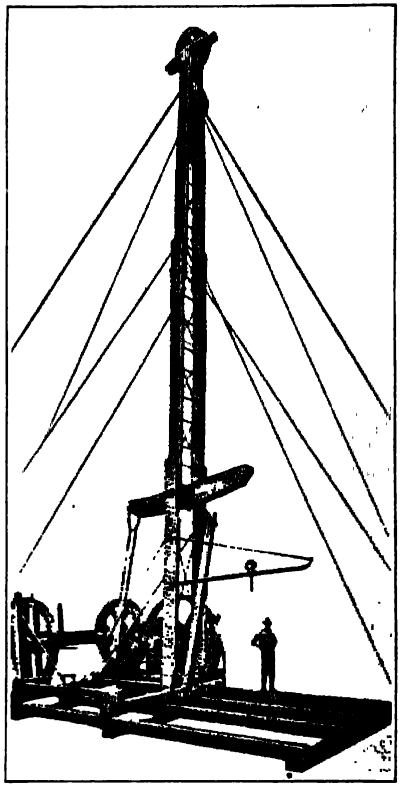
The No. 30 Star machine (see Fig. 58) is equipped with a 60-ft., single-pole timber mast, sectionalized to facilitate transportation, with additional shear poles provided for bracing the mast when very heavy lifting is necessary, and 12 guy wires. Three pulleys are mounted on or near the upper end of the mast to support the drilling cable, sand line and calf line. A walking beam 22 ft. long is mounted on a slanting Samson post at one corner of the truck and heavily braced to one side. The 35-hp. steam engine is mounted at the same end, a belt connecting from its flywheel to a 92-in. wooden band wheel, mounted on one side of the truck and serving as a power distribution center for the entire machine. In the case of the No. 30 model, the boiler is mounted on a separate wheeled truck, but in smaller sized machines it is carried on the end of the same truck that supports the drilling machinery. A crank mounted on the band wheel shaft operates the walking beam through a connecting wristpin and pittman. The 60-in. bull wheel or drum, supported at the center of the truck and driven by gearing from the band wheel shaft, is equipped with a reel large enough to spool 2,500 ft. of 2¼-in. hemp cable, and with a heavy band brake. A sand reel driven by a belt from a countershaft, operated by a friction pulley bearing on the face of the band wheel, actuates the bailer. A calf wheel for handling casing is also built into the machine. This is operated by gearing from the band wheel shaft. Instead of suspending them from a temper screw on the end of the walking beam, the

drilling tools may, if desired, be operated by a spudding attachment mounted in a slot on the crank.

The weight of the No. 30 Star machine complete with boiler and tools is about 52,000 lb., too heavy to move without partially dismantling except on very well-built roads. The main frame of the truck is 6 ft. wide by 23 ft. long. It is claimed by the manufacturers that this machine is the equal in every respect of a heavy stand-



(Star Drilling Mach Co., Akron, Ohio).
FIG. 58.—Star portable drilling machine.



(National Supply Co., Toledo, Ohio).
FIG. 59.—National semi-portable drilling rig.

ard cable rig, being capable of handling the same sized tools and an equal weight or length of casing. The No. 30 machine described above is used less than the lighter and medium-sized machines designed for shallower depths. Some of the lighter rigs weigh only 7,000 lb. One commonly used medium-sized machine (No. 26), designed for drilling to 2,200 ft., weighs about 27,000 lb.; with tools and incidental equipment, about 35,000 lb. One well 2,825 ft. deep was drilled with a No. 26 machine in 45 days.

The Columbia driller is an all-steel, portable machine designed to supplant the stationary cable tool rig commonly used in drilling oil wells to shallow and moderate depths. The larger sizes are rated for nominal depths as great as 2,000 ft They may be had equipped with either steam or gasoline engines, and some sizes have a traction drive. Weights range from 4,000 to 26,500 lb.

A belt-driven band wheel, a bull wheel drum driven by a large gear wheel operated from the engine crankshaft, and a sand reel for operating the bailer, are provided in all models and a calf wheel attachment operated by a chain and sprocket drive may be added if desired for handling casing. Distinctive features of this machine include the cross-connected, double, steel walking beams, each mounted on a well-braced Samson post located one on either side of the truck, and the two-legged braced steel mast mounted at one end of the truck with the legs between the walking beams. The mast is built with a knee joint, so arranged that it can be lowered and carried on top of the truck when the rig is being moved. The Columbia machine may also be used to operate a rotary drilling table, which is provided as an additional attachment if desired. A duplex slush pump is necessarily also a part of the equipment if the rotary outfit is used. With the rotary attachment the Columbia machine thus becomes the equivalent in every essential respect of a light "combination" stationary rig.

The National semi-portable drilling rig resembles more closely the ordinary standard cable rig than do the machines mounted on wheeled trucks described above. The chief difference, in comparison with the standard rig, lies in the use of a braced, 2-legged mast instead of a derrick, and a more compact arrangement of the rig wheels and parts. The rig wheels and controls are mounted on a bolted wooden frame, and are of such weight and so compact that the whole machine can be placed on a truck and moved as a unit from one location to another. The mast is built in sections which can be readily dismantled or assembled. The walking beam, instead of being mounted on a Samson post, is supported on trunnions between the two legs of the mast. The machine is built in two sizes, No. 1 for drilling to a depth of 1,600 ft. and for handling a 17,000-lb. string of casing, and No. 2 for drilling to 2,500 ft. and handling 30,000 lb. of casing.

The No. 2 machine is illustrated in Fig. 59. Power is received from a steam engine (not a part of the equipment) by belt, on a wooden band wheel 10 ft. in diameter. Both the 7-ft. bull wheels and the sand reel are operated by a wooden friction drum 5 ft. in diameter with a 16-in. face, mounted on the band wheel shaft. A hoisting drum for handling casing, which can be adapted to the rig if desired, is operated by a chain and sprocket drive from the end of the band wheel shaft, and is equipped with a clutch and a heavy band brake. The braced mast is about 65 ft. high and is made up of 12-in.-20.5 lb. channel steel, suitably braced, and built in three sections. Timber masts of similar design may also be had if preferred. At the upper end of the mast, a 43-in. crown pulley is supported, and smaller sheaves are provided below for the sand line and casing line. The mast is hinged to one of the oak sills for convenience in hoisting it into position, the power being used to assist in this operation. The walking beam, supported between the derrick legs, is operated by a pittman attached by a wristpin to the crank mounted on the end of the band-wheel shaft. The beam is considerably shorter than that provided in the standard cable rig. This method of supporting the walking beam, and the friction drive used for operating the bull wheels, are the distinctive features of the National rig.

Advantages and Disadvantages of Portable Rigs.—The portable rigs have certain well-defined advantages and limitations. For drilling in shallow territory, the cost of the well may be materially reduced since there is no necessity for the building of a derrick or other expensive fixed-surface plant. Shallow wells can often be operated in multiple with a simple pumping jack at each well, and such repairs as are necessary after the well becomes a producer may also be handled by a portable pulling outfit mounted on a truck. Under such conditions the portable rig has

become a serious competitor of the standard rig. For prospecting work, where the formations to be tested are within reach of the portable machines, they have the great advantage of ease in transportation. They are more readily dismantled and reassembled, and therefore have a relatively greater salvage value after drilling a dry hole.

One of the serious disadvantages of most of the portable rigs is found in their inability to handle satisfactorily the heavy strings of casing necessary in drilling through unconsolidated sands and caving formations. In many regions where the tools can be operated in uncased holes to great depths, of course this limitation is not a serious matter. Some of the manufacturers, in striving to adapt their machines to more difficult conditions, are giving attention to this phase of the work and have added calf drums which, while mechanically weak in most cases, are a step toward a real solution of the difficulty. Another disadvantage, in comparison with the standard rig, is the relatively short stroke of the walking beams or spudding devices provided in most of the portable machines. The beams are usually from 2 to 6 ft. shorter; and at depths greater than 1,500 ft., when stretch in the cable becomes a factor of importance, the effective stroke of the tools becomes so short that the portable rig is much less efficient. Though some of these rigs are rated by the manufacturers for depths in excess of 3,000 ft., it is doubtful if many operators would undertake the drilling of a deeper hole than this with a portable rig. The principal field of most of the portable rigs, as at present designed, would appear to be in drilling wells in formations that do not cave readily, and to depths not greatly in excess of 2,500 ft.

THE STANDARD CIRCULATING SYSTEM OF DRILLING

In an effort to devise a means of drilling through unconsolidated sands and caving formations of the California San Joaquin Valley fields to depths of more than 3,000 ft. with cable tools, and to reduce the number of strings of casing necessary in so doing, the so-called "circulating system" of drilling was developed. This method involves the use of the complete standard cable equipment, and, in addition, a pair of high-pressure slush pumps such as are used in rotary drilling, with flexible connections to a "circulating head" supported by a massive "swinging spider" on which the casing in the well is suspended (see Fig. 60). The purpose of the additional equipment is to provide a means of "mudding" the soft material in the walls of the well so that it does not cave about the casing, a process commonly employed in rotary drilling (see page 172). Mud-laden water is pumped down through the casing, passes under the casing shoe, which is lowered as the bit progresses, and back to the surface in the annular space between the casing and the walls of the well. In order to keep this space clear, the casing is frequently raised for a few feet and

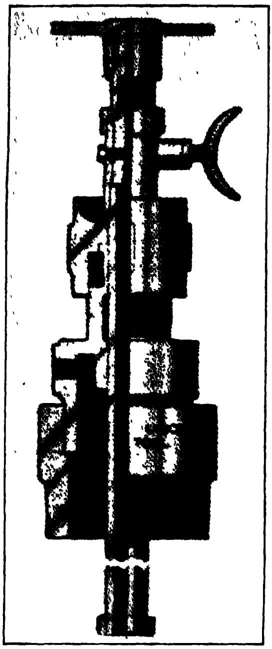
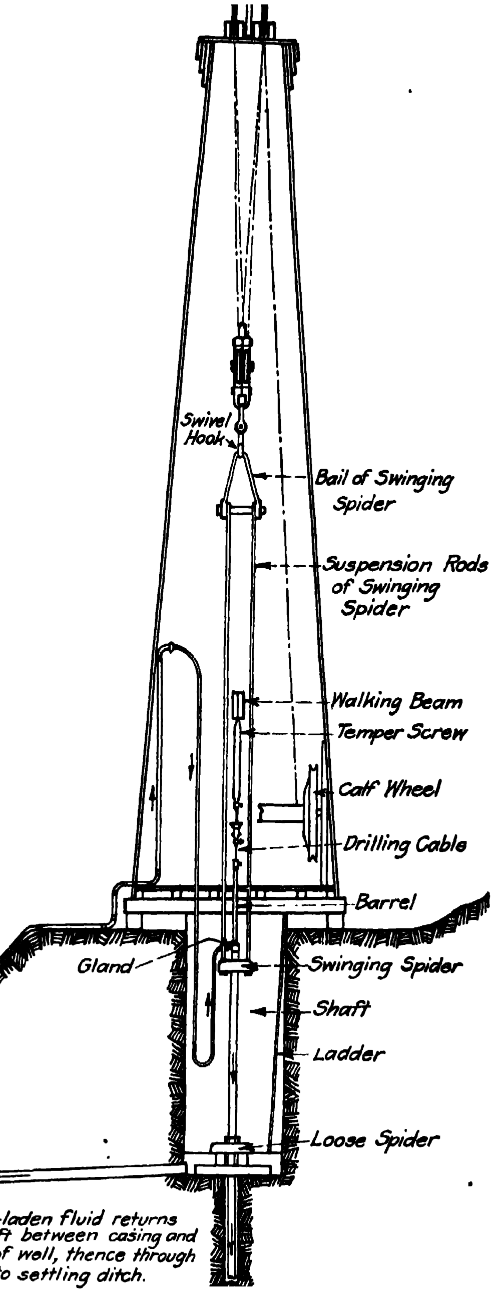
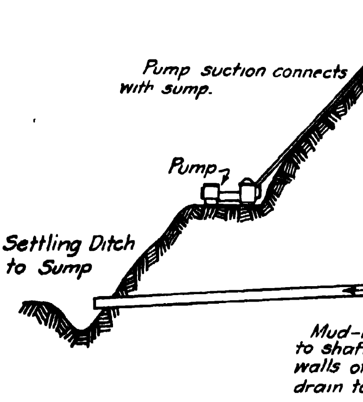


FIG. 61.—Circulating head.

(*After A. B. Thompson, with additions*).

FIG. 60.—Sketch showing arrangement of equipment for standard-circulating system of drilling.

lowered with the swinging spider, which is supported by a large hook and hoisting block strung on the casing line from the derrick crown block. The circulating fluid, in addition to mudding the walls of the well so that they do not cave, serves to lift a part of the material loosened by the drill, so that less bailing of the well is necessary.

The cable tools operate in the usual manner, except that the drilling cable works through a stuffing box in the circulating head, which prevents leakage of the mud-laden fluid as it is pumped down through the casing. The stuffing box is so designed that it does not seriously interfere with the lowering and withdrawal of the drilling tools (see Fig. 61). A polished plunger is fastened around the drilling cable by means of rope clamps, which on being released allow the cable to be drawn from the well through the circulating head until the rope socket emerges from the well. The bolts which fasten the stuffing box in the circulating head are then loosened and the entire top of the head with the polished plunger and stuffing box are lifted out with the tools, leaving the full cross-section of the casing free for bailing or other operations. In lowering the tools into the well to resume drilling, the top of the circulating head is bolted in position as soon as the tools have entered the casing, but the plunger is not clamped to the cable until the tools have reached drilling position at the bottom of the well and have been hitched to the beam.

The temper screw plays between the two reins of the swinging spider, which are about 40 ft. long. The cellar should be about 30 ft. deep, and of ample size to permit of proper manipulation of the swinging spider. At the cellar bottom, a stationary casing spider is placed, which supports the pipe in the well when a new joint is added. The column of casing in the well is raised and lowered with the swinging spider at intervals of from 10 to 20 min. without interruption in drilling. The pumps connect with side openings in the circulating head through armored hose. Returns from the well flow through a trough in which the coarse sand settles, to a mud pit where the fluid is taken in by the pump suction lines for repeated circulation through the well.

It is important, when this system of drilling is used, to maintain ample clearance between the casing and the walls of the well, thus eliminating danger of sand lodging around the pipe and interfering with circulation of the well fluid, or of freezing the working string of casing. An unusually heavy casing shoe is employed and all hard formations are underreamed until the casing can be lowered freely. Also, the casing used is somewhat smaller in diameter than the casing normally employed in a hole of the size drilled. When a conductor pipe is landed, the clearance necessary to maintain circulation of the well without the application of abnormal pressure, is obtained by skipping one size of pipe in the usual series of telescoping sizes; thus, a 10-in. casing may be used inside of a 15½-in. conductor string instead of a 12½-in. It is usually important to

maintain fairly continuous operation of one or another of the two pumps. A shut-down of more than an hour or so may result in settling of the mud, causing freezing of the casing or loss of circulation.

This method of drilling has been given a sufficient trial in the oil fields of California, to prove definitely that it is practical, and that it has certain advantages over the ordinary cable drilling method, in drilling through unconsolidated caving formations.[10] The most important advantage is that by the use of it, strings of large-diameter pipe can be carried to unusual depths without danger of freezing. This often results in the saving of one or more strings of casing, and leaves a larger available working diameter in the bottom of the well. Better drilling time results from the absence of casing difficulties and because bailing is not so frequent an interruption. Through the use of the circulating mud-laden fluid, better control of high gas, oil and water pressures is afforded. While the additional equipment necessary is costly, the added expense is offset by the saving in casing and more rapid progress.

Notwithstanding the demonstrated advantages of this method of drilling, it is now rarely if ever used because the rotary method has been found cheaper and even better adapted to the conditions against which it was designed to contend. Nevertheless, it is but a few years since a considerable number of wells were successfully drilled by this method, and the records made with it compare favorably, except for the greater cost, with those achieved by the more modern rotary equipment. In one well, a 15½-in. string was set at 2,300 ft. and a 12½-in. string through this, at 3,003 ft. In another well, the 15½-in. string was set at 2,100 ft. and a 10-in. string at 3,300 ft. In each case the casing was entirely free in the well, though previous drilling in the same territory by ordinary standard cable methods had shown that the walls could not be maintained for more than 40 or 50 ft. ahead of the pipe.

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CHAPTER VI

ROTARY DRILLING METHODS

Classification of Rotary Drilling Methods.—Of the various systems of drilling that operate with rotating drilling tools, five seem worthy of mention in a broad classification. These are:

1. Methods of drilling which completely pulverize the material taken from the well:
   (*a*) The hydraulic rotary system
   (*b*) The Davis calyx drill
   (*c*) The Empire drill
2. Methods of core drilling in which a part of the material is withdrawn from the well as a solid cylindrical core:
   (*a*) Diamond drilling
   (*b*) Abrasive and chilled-shot core drilling

While the latter four systems are used to some extent for prospecting in metal mining, and in drilling to secure information for making excavations in building foundations and other engineering work, they have not been used to any appreciable extent in drilling for oil. The present chapter will therefore be concerned chiefly with the hydraulic rotary system, the only one of this group that has found important application in the drilling of oil wells.

THE HYDRAULIC ROTARY SYSTEM OF DRILLING

Historical Development of the Hydraulic Rotary System.—The hydraulic rotary system of drilling, though of comparatively recent origin in comparison with the "standard" cable drilling system, has reached a high state of development, and probably in excess of 75 per cent of the footage drilled in the western American fields within recent years has been by this method. The method was first used in drilling for oil in 1901 in the Spindle Top field near Beaumont, Tex., where the formations overlying the oil zone consist of unconsolidated sands and shales that cave seriously when subjected to the vibrations of churn drilling tools. During the last 20 yr. the rotary method has grown in popularity until it is now extensively used in most of the mid-continent, gulf coast and California fields, particularly where soft formations are the rule. Development of hard rock drilling bits for use with rotary equipment has in

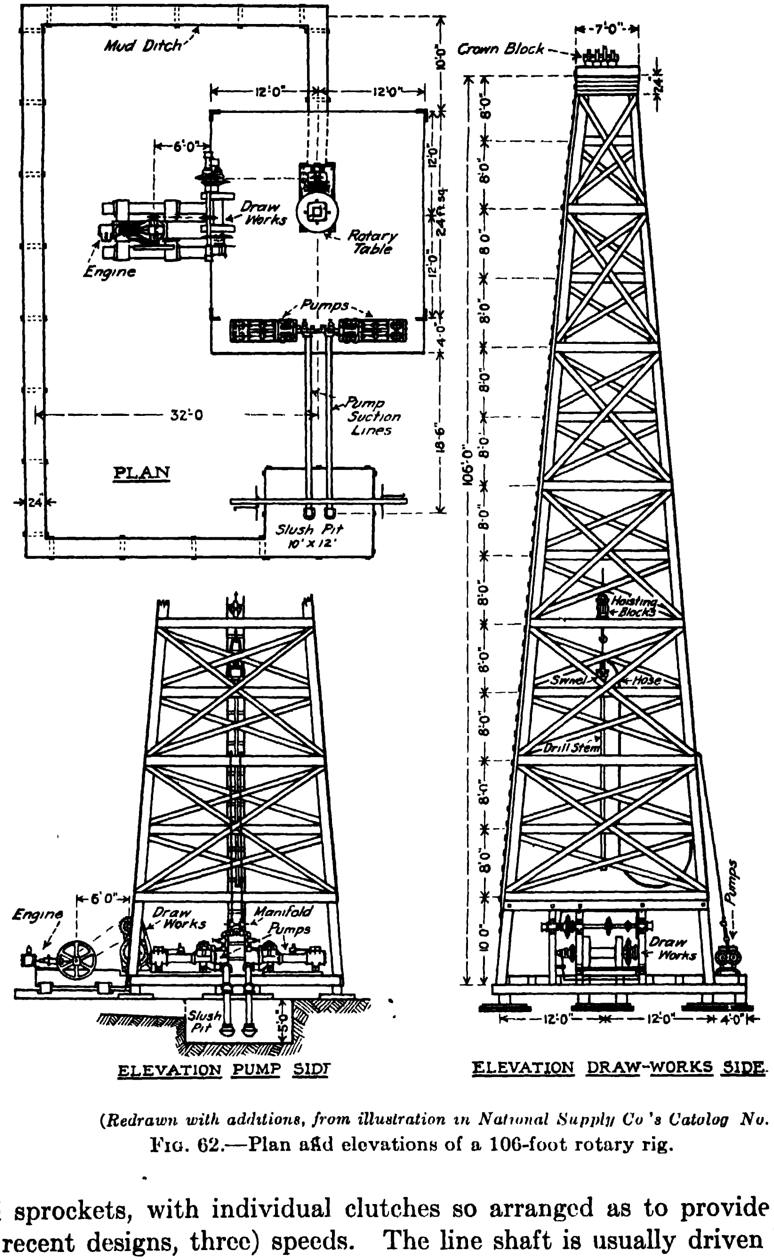
recent years extended its field of usefulness until at the present time there is scarcely any type of rock ordinarily encountered in the American oil fields that cannot be satisfactorily drilled by the rotary method. However, there are disadvantages, to be considered in a later section, that under certain conditions render the rotary method less effective or desirable than the standard cable method. Though the rotary method has rapidly gained in popularity and is more extensively used because of its greater speed and lower unit cost, it does not necessarily follow that the standard cable system is obsolete or is about to become so.

General Features of the Hydraulic Rotary System.—(See Figs. 62, 63, and 64.) In the hydraulic rotary system of drilling, the rock mass through which the well is drilled is abraded and chipped away by the downward pressure and cutting and grinding action of a revolving steel bit which may assume various forms. The cutting bit is revolved by a substantial steel pipe or "drill stem," extending from the top of the drilling tool, to which it is screwed, to a point some distance above the derrick floor. At the level of the derrick floor the drill stem passes through a gripping device in a power-driven rotary table mounted over the mouth of the well. The form of the gripping device is such that while the table has a positive grip on the drill stem, the latter is free to move vertically through the table, even while it is in motion.

To the top of the column of pipe comprising the drill stem, a massive swivel is attached, which provides a means of suspending the stem in the well, allowing it to rotate with the table, while the upper part of the swivel, the hoisting block and supporting cables remain stationary. The drill stem and swivel are hollow, so that water or mud can be pumped down through the stem to the drilling bit and out into the well through two holes provided, one on either side of the bit. This fluid sweeps under the bit, picks up the rocky material loosened thereby and carries it to the surface through the annular space between the drill stem and the walls of the well. This circulation of fluid through the well is maintained by the pressure of either of two powerful pumps connecting through an armored flexible hose to the swivel on top of the drill stem. Fluid from the well overflows into a mud ditch or wooden trough through which it flows sluggishly, allowing the coarse cuttings from the well to settle. The fluid thus freed of the coarse gritty material, and containing only fine-grained clay in suspension, flows into the mud sump, from which it is picked up by the pump suction for further circulation through the well. The mud fluid, thus used repeatedly in closed circuit, need only be replenished to the extent that it is absorbed by the porous formations penetrated by the well.

The swivel, drill stem and bit may be raised or lowered in the well by means of a steel cable, operating through a massive hoisting block strung from sheaves at the derrick crown. The free end of this cable passes

down through the derrick and is wound on a heavy hoisting drum supported by metal bearings mounted on three substantial oak posts (see Fig. 80). The hoisting drum is driven from a line shaft by chain belts



(*Redrawn with additions, from illustration in National Supply Co's Catalog No. 30*).

FIG. 62.—Plan and elevations of a 106-foot rotary rig.

and sprockets, with individual clutches so arranged as to provide two (in recent designs, three) speeds. The line shaft is usually driven by a chain belt from a sprocket on the crankshaft of a steam engine, though a

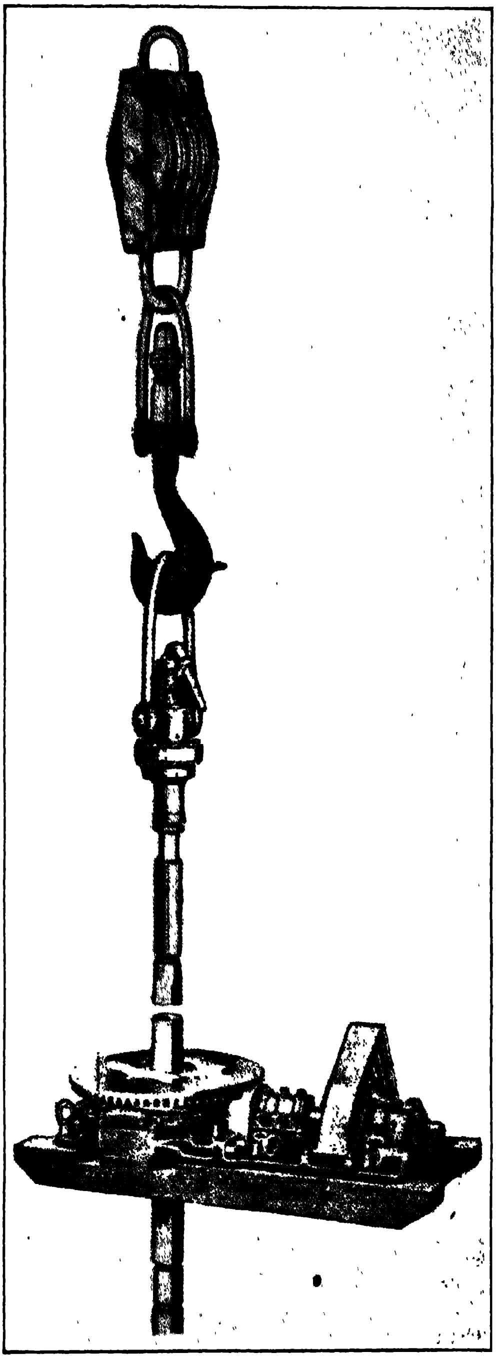


FIG. 63.—Assembly view of rotary table, grief stem, swivel, traveling blocks and hook.

variable speed electric motor can be adapted to the work through the use of intermediate gearing. Heavy band brakes on the flanges of the hoisting drum permit of suspending the weight of the drill stem and swivel when the power clutches are disengaged. On the line shaft there is also a sprocket for a belt drive, which operates the rotary table. The latter connects either directly with the jack shaft of the rotary table, or indirectly through an intermediate drive shaft. The drive shaft may also support an additional sprocket for operating a mechanical mud mixer,

FIG. 64.—Rotary draw works and chain-driven rotary table.

and two cat heads useful in applying power to the heavy pipe tongs used in tightening the joints of the drill stem, and for other purposes. The hoisting drum with its supporting shaft, the drive shaft, sprockets, brakes, clutches and supports, are known collectively as the "draw works," commonly furnished as a unit by manufacturers specializing in rotary drilling equipment.

The size and weight of the equipment used varies according to the diameter and depth of the hole to be drilled. Preference as between light and heavy equipment also varies in different fields. For example, the rotary equipment used in Texas and Louisiana is lighter than that used in California.

The rotary derrick is a higher and heavier structure than the derricks described in the previous chapter for cable drilling, but is otherwise similar in form and design. The height is generally 106 ft. The space enclosed within the four legs is 24 ft. square at the level of the derrick floor and 5 ft. square at the crown. The legs are reinforced with "doublers" for the full height, and if the well to be drilled is a deep one, sway bracing is applied on the outside of each panel between alternate girts.

The engine housing is but little more than a low lean-to structure or an extension of the housing at one side of the derrick (see Fig. 62). There is, of course, no occasion for the belt house and plank walk described in connection with the standard cable rig.

A platform of 2-in. plank is built across one side of the derrick at about the level of the ninth girt above the floor, to provide the necessary footing for the derrick man in manipulating the upper ends of the "stands" of drill stem as they are screwed or unscrewed. This platform is frequently extended and carried around the outside of the derrick, and railings are built around the outer edge for greater security of the derrick man in moving from one side of the derrick to the other. The square space on top of the derrick about the crown block is similarly enclosed as a protection to one engaged in inspecting or oiling the sheaves or in stringing the hoisting cable over them. Such platforms and hand railings are required by law in California as an accident preventive. Reinforcement of the derrick floor across the side where the sections of stem are placed on end when not in the well, and suitable timber braces and guides to keep them in position in the upper portion of the derrick, are also important considerations.

A shallow cellar is excavated beneath the derrick, in which a vertical "conductor pipe" of riveted steel, corrugated pipe, or wood staves is placed and carefully plumbed and braced. A rectangular hole is cut or is left in the center of the derrick floor, of the same size and shape as the metal base of the rotary table, the timber frame to which the rotary is bolted resting directly upon the derrick center sills. The latter, in turn, are supported on substantial posts resting on concrete piers or timber footings.

A mud pit of adequate capacity is excavated at one side of the derrick, conveniently placed for the pump suction lines. A wooden trough 24 in. wide and 12 in. deep, at least 125 ft. long and graded to a slight slope, is constructed about three sides of the derrick at or slightly above the ground level. It is arranged at one end to receive the overflow of fluid from the well, and discharges at the other end into the mud pit (see Fig. 62). A supply of clay of suitable character is hauled from the nearest available source and piled ready for use at one side of the mud pit or mud mixing machine.

Rotary Drilling Bits

A number of different types of bits are used in rotary drilling, a choice depending chiefly upon the nature of the formation to be penetrated.

The Fishtail Bit.—The usual form of rotary bit is the "fishtail" bit, shaped as illustrated in Fig. 65. It is made of a special grade of tool steel, often of chrome steel, forged to a slender blade ranging from 15

to 30 in. in length, ½ to ¾ in. thick at the cutting edge and 1½ to 2½ in. thick at the top. The width of the blade at the cutting edge is only slightly smaller than that of the hole which it is desired to drill. The cutting edge is divided into two parts by fluted water courses down the center of each side of the blade. The two cutting wings thus formed, are dressed to a slight taper or bevel and turned back somewhat to form the cutting edges. The top of the flattened portion of the bit terminates in a rounded shank, externally screwed for connecting the bit to a heavy drill

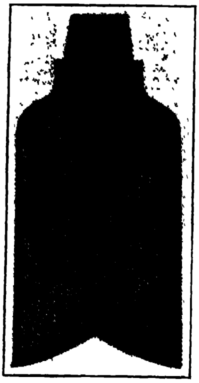


FIG. 65.—Fish tail bit.

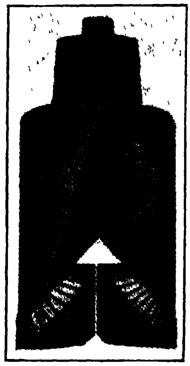


FIG. 66.—Hughes reaming cone bit.

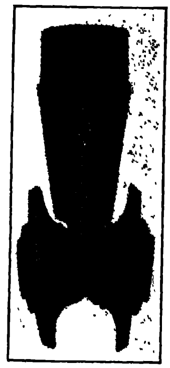


FIG. 67.—Hughes disc bit.

collar on the end of the drill stem. Through each side of this shank is bored a ¾-in. hole through which water or mud-laden fluid from the hollow drill stem emerges, sweeps down the sides of the bit and is deflected upward on striking the bottom of the hole.

The fishtail bit is used by preference whenever the formations to be penetrated are soft or moderately soft rock. It is especially adapted to loosely cemented sands, shales and clays. When harder rocks are encountered, however, the bit is rapidly dulled and progress is slow.

Rotary Cone and Disc Bits.—For drilling in hard formations, various types of revolving cone and disc bits have been devised. One of the most successful of these is the Hughes reaming cone bit,* illustrated in Fig. 66. The principal drilling elements in this bit consist of two cones, on the surfaces of which there are milled a large number of cutting teeth. These cones revolve on supporting pins in such a way that the element of the conical surface in contact with the bottom of the hole is almost horizontal, or preferably inclined a few degrees below the horizontal from the axis of the tool. The main body of the tool consists of two semi-cylindrical segments held together by a locking screw, and a massive drill collar screwed to the lower end of the drill stem. In addition to the cone cutters, the tool is equipped with two cylindrically shaped cutting

* Manufactured by Hughes Tool Co., Houston, Tex.

rollers, mounted on opposite sides of the cylindrical body. These rollers have teeth milled on their cylindrical surfaces and they are so mounted that the rollers cut lightly into the vertical walls left by the cones. The rollers thus serve to ream the hole to a slightly larger diameter, giving all parts of the tool ample clearance and producing a smooth and perfectly cylindrical hole. In addition to the main features of the reaming cone bit described above, there are provided an elaborate oiling system and water courses for conducting the mud-laden fluid from the hollow drill stem through the body of the tool to the revolving cones, against the surfaces of which the fluid is discharged under high pressure.

It is claimed by the manufacturers of the reaming cone bit, that instead of abrading the rocky material by scraping or dragging, the tool actually crushes and chips away the rock, flakes 1/16 in. thick, 3/8 in. wide and 3/4 in. long being cut by the drill when operating in certain kinds of rocks under proper pressure and speed. Normally, however, the returns circulated to the surface will consist of coarse granular material.

Of course, the teeth of the cone and reaming rollers gradually wear away under the abrasive action of the rock, and the moving parts must be periodically replaced. This involves withdrawal of the tool from the well, disassembling and assembling the various parts with fresh cutters. Under average conditions in the mid-continent and gulf-coast fields, these bits will drill about 5 ft. of hole per hour and from 100 to 200 ft. will be drilled with one set of cutters. Under exceptionally favorable conditions, drilling speeds as high as 15 to 18 ft. per hour have been recorded, with as much as 800 ft. of hole drilled with one set of cutters without resharpening. The cutters may be redressed in a milling machine after annealing, for use in a smaller sized hole.

The greater footage obtained with the cone bits is in part due to the greater linear length of cutting edge. For example, in a pair of 9 7/8-in. cutters there are 56 teeth, each 3 in. long, or a total of 168 in. of cutting edge, as compared with perhaps 11 in. for the ordinary fishtail bit.

Another type of bit that has met with some success in drilling moderately hard rocks is the Hughes disc bit illustrated in Fig. 67. It is urged by the manufacturers as a desirable substitute for the fishtail bit in drilling such rocks. The cutting elements consist of two saucer-shaped discs having teeth milled on their outer edges, and so mounted that they revolve on their inclined supporting pins as the drill stem revolves. Like the cone bits, they have a cutting and crushing action on the rock formation. The manufacturers claim that the disc bit has 13 times the linear length of cutting edge possible in a fishtail bit, and that it therefore drills faster and lasts longer. It has been used successfully in some of the mid-continental and Rocky Mountain fields where footages as high as 300 ft. per day have been obtained with it. A somewhat similar bit, utilizing revolving, saucer-shaped discs, is illustrated in Fig. 68. This

bit is used to some extent in southern California as a substitute for the fishtail bit, in drilling through soft and moderately hard formations.

While the cone and disc bits are considerably more expensive than the fishtail bit, the cost of the bit is but a small part of the total cost of drilling when reduced to a footage basis. The cost of operating a rotary rig ranges from $100 to $150 per day, and when the wear and tear on the drill stem resulting from the use of a slow cutting, rapidly dulled bit

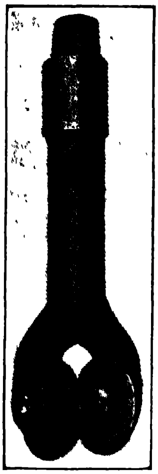


FIG 68. Rotary disc bit.

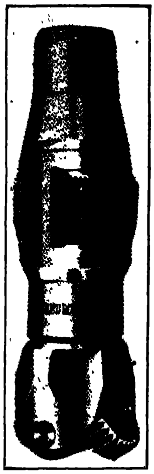


FIG. 69.—Reed roller bit.

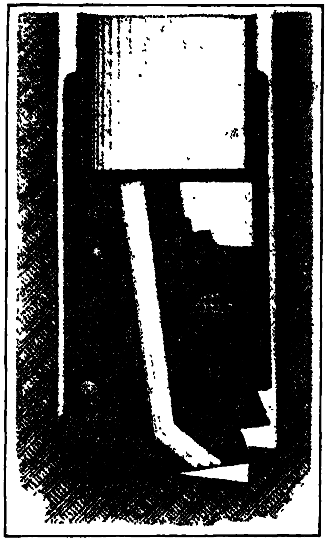


FIG. 70.—Pickin gyrating bit.

is considered, together with the cost of replacing it frequently, and the increased risk of twist-offs resulting in expensive fishing jobs, it is apparent that a rapidly cutting, long-lived bit is able to meet a considerable handicap in the way of additional first cost.

The Reed roller bit,* a competitor of the Hughes cone bit in hard-rock rotary drilling, is illustrated in Fig. 69. This bit is equipped with eight disc-shaped cutters having teeth milled around their circumferences, and mounted in a massive steel frame. The discs are smaller in diameter toward the center of rotation, in order to compensate for differences in rate of travel. The two cutters set at an inclination with the axis of the tool, are provided to maintain clearance. Four additional sets of cutters, mounted vertically on the circumference of the main body of the tool, serve to ream the hole further, and to give a smoother bore. A reservoir of lubricating oil in a lubricator attached between the drill collar and the bit is connected by oil courses to the moving parts. The circulating

* Manufactured by Reed Roller Bit Co., Houston, Tex.

fluid is passed through the bit by two water courses connecting with the drill stem, and is discharged directly against the cutters.

The Pickin rotary rock drill (see Fig. 70) contains a bit, so mounted that it revolves eccentrically with a combined cutting and grinding action on the rock formation. The cutting face is almost horizontal and is notched with shallow cutting teeth. The moving parts of the bit are supported by a substantial sleeve on the lower end of the hollow drill stem, and ball bearings are provided between the fixed and moving parts to reduce friction. A water course through the bit permits the escape of circulating fluid from the drill stem. The Pickin drill is said to be particularly effective in drilling in hard rock, and since it maintains adequate clearance by reason of its eccentric motion, it is well adapted to drilling in a deep well of small diameter.

Other types of rotary bits have been developed for special purposes and are occasionally used. The diamond-pointed bit (see Fig. 71) is similar in form and general dimensions to the fishtail bit, except that the cutting end is dressed to a point at the center and the cutting wings are not offset. It is useful in drilling past pipe, tools or metal objects that have become lodged in the well. It is also used as a part of certain rotary fishing tools, such as the wash-down spear used in recovering broken sections of drill stem that have twisted off during the process of drilling, and about which the circulating mud has settled.

The drag bit (see Fig. 72) is divided into two cutting wings with water courses between, as in the case of the fishtail bit, but is thicker than the latter and has the edges reversed or turned in the opposite direction to the direction of rotation, so that they drag as the bit revolves. This form of bit is occasionally used in drilling through hard rock, adamantine or other abrasive material being dropped into the well. The abrasive lodges under the bit and is dragged around as the latter revolves, thus hastening the cutting action.

For enlarging a hole drilled by rotary methods, a special bit called a "four-way reamer" is often used (see Fig. 73). This is a tapered tool, similar in form to the fishtail bit, except that it has four wings instead of two. Water courses connecting with the hollow drill stem are provided between the wings, as in the case of the other bits. The reamer is used to enlarge the hole when the drilling tool regularly used has for one reason or another failed to maintain proper clearance. All restrictions in the prescribed diameter of the hole must be carefully reamed in order that they will not interfere with the passage of the metal casing.

Under-reamers very similar to those described in connection with cable drilling are occasionally used with rotary equipment (see Fig. 74). Under-reamers permit of reaming an enlargement in the hole without the necessity of reaming it for its entire depth. These tools are equipped with cutters which are collapsed before entering the casing at the surface,

but by the action of a powerful spring, expand to working position after passing below the casing shoe, and are then capable of drilling a hole several inches larger than the openings through which they pass while in the collapsed position. Rotary under-reamer cutters are dressed to a

FIG. 71. -Diamond pointed bit.

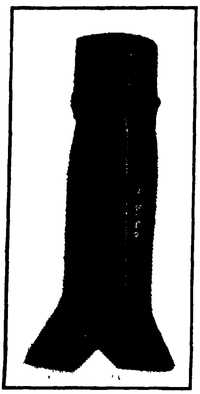


FIG. 72.—Drag bit.

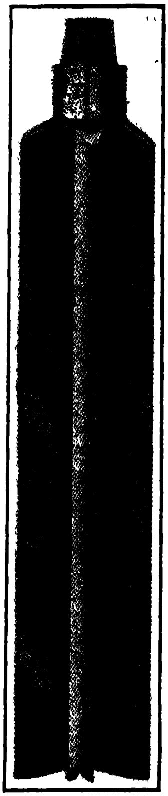


FIG. 73.—Four-wing rotary bit.

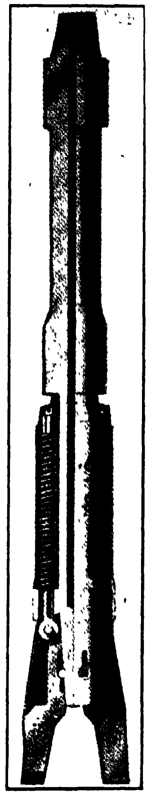


FIG. 74.—Rotary under reamer.

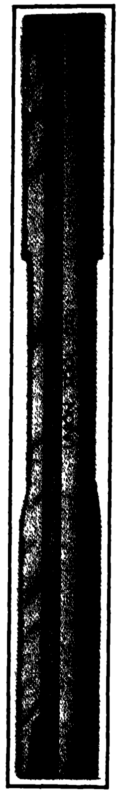


FIG. 75.—Drill collar.

cutting edge on the sides as well as on the lower edge. Many operators contend that the use of under-reamers with rotary equipment is conducive to "twist-offs," but if properly handled the type illustrated gives little trouble and is quite as reliable in action as the cable tool under-reamer.

In addition to the several types of rotary bits described above, a variety of different coring and sampling devices have been developed within recent years, for use with rotary equipment. These might properly be discussed at this point, but are reserved for a later section of the present chapter.

The drill collar, which provides a means of attaching the rotary bit to the drill stem, must be of sufficient strength to withstand the great torsional strain to which it is subjected. Every precaution must be taken against breakage of the stem and the connecting collars and tool joints, and the portion just above the bit is subjected to greatest strain. The drill collar is equipped with a tool joint at the lower end and a pipe thread connection at the upper end. It is hollow to permit of passage of circulating fluid to the bit (see Fig. 75).

TABLE XIII.—DIMENSIONS AND WEIGHTS OF ROTARY DRILL PIPE*

Regular

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
4	4.500	4.026	.237	10 790	11 055	8	5.228	5⅛	8.901
4	4 500	3 990	.255	11 561	11 815	8	5 228	5⅛	8.901
4½	5.000	4 506	.247	12 538	12 744	8	5 604	5⅛	8.270
5	5.563	5 047	258	14.617	15 055	8	6.373	6⅛	14.620
6	6.625	6.065	.280	18 974	19.463	8	7.435	6⅛	17.254

Special

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
2½	2.875	2.323	.276	7.661	7.830	8	3.603	5⅛	5.888
2½	2.875	2 143	.366	9.807	10.000	8	3 693	5⅝	7.316
4	4.500	3 958	.271	12.240	12.500	8	5.228	5⅛	8.901
4	4.500	3 826	.337	14 983	15.000	8	5.240	6⅛	11.720
4½	5.000	4 388	.306	15 340	15.500	8	5.604	5⅛	8.270
4½	5.000	4.290	.355	17.611	18 000	8	5.740	6⅛	12.950
5	5.563	4.955	.304	17.074	17.500	8	6.373	6⅛	14.620
5	5.563	4.813	.375	20.778	21 000	8	6.272	7⅛	16.442
6	6.625	5.937	.344	23.076	23.500	8	7.435	6⅛	17.254
6	6.625	5.761	.432	28.573	29.000	8	7.334	7⅛	19.451

* As manufactured by the National Tube Co.

(All dimensions are given in inches, weights in pounds)

The drill stem, connecting the bit and drill collar in the well with the hydraulic swivel in the derrick, consists of sections of heavy steel pipe, approximately 20 ft. in length, connected by special pipe couplings or "tool joints." Tool joints are used only at every third or fourth joint (depending upon the height of the derrick), and are designed to facilitate coupling and uncoupling the stem as it is inserted into or withdrawn from the well.

Rotary drill pipe, the trade name applied to the special grade of pipe used for the drill stem, may be had in nominal diameters ranging from 2½ to 6 in. (see Table XIV), but the 4-in. and 6-in. sizes are most used.

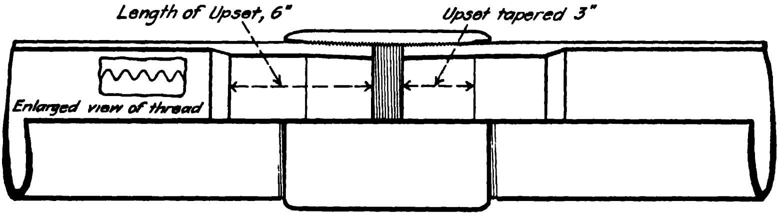


FIG. 76.—Upset-end "National" rotary drill pipe.

Recently experiments have been conducted with 8-in. drill pipe. Each size may be had in several different weights or thicknesses, varying from a little over ½ in. to nearly ⅞ in. Selection of the size of stem depends upon the diameter of the hole to be drilled, the strain on the stem increasing directly with the diameter of the bit.

The strain imposed on the rotary drill stem results chiefly from the twisting effect developed by the drag of the revolving bit on the bottom of the well. The resulting torsional strain is resisted or absorbed by the elasticity of the steel, so that it is progressively diminished as we proceed upward from the bit. For this reason, most twist-offs, or breakages of the drill stem as a result of torsional strain, occur near the lower end, and particularly when drilling in hard rock requiring increased pressure on the bit. Fractures of the drill stem often occur at the threaded joints, the weakest cross-section being at the base of the threads. In order to reinforce the pipe at this point, an upset-end pipe is frequently used, the surplus metal being placed on the inside of the pipe (see Fig. 76). Torsional tests made on 4-in., 12½-lb. rotary pipe indicate an increase of about 36 per cent in the strength of the joint by use of the upset-end pipe.

The metal walls of the drill pipe must also be thick enough to support the dead weight of the stem itself, when suspended in the well. The dead load of course increases directly with the depth, and in very deep wells with large-size drill pipe, becomes a force of some magnitude. Hydrostatic pressure is not ordinarily a force worthy of consideration

since the entire free space within the well will be filled with fluid and the pressure within the stem will not ordinarily be greatly in excess of that without. Occasionally, however, when mud has settled about the stem, hydrostatic pressures of from 500 to 1,000 lb. may be applied with the pumps to re-establish circulation. Drill pipe heavy enough to withstand the torsional strain resulting from rotation of the bit will be able to withstand all hydrostatic pressure and dead loads to which it will normally be subjected.

The couplings provided for drill pipe are of special design, with recessed threads and heavier than standard couplings in order that they may withstand the severe strains imposed upon them. They are cut with eight 60-deg. V-shaped threads per inch, a deep thread in order to avoid stripping under severe strain.

In inserting and withdrawing the drill stem into and from the well, it is broken only at every third or fourth joint, and the resulting stands of drill pipe, called "thribles" or "fourbles" by the drillers, are stood on end in one corner of the derrick. The couplings described in the preceding paragraph are ordinarily used only at joints that are not frequently unscrewed. The tool joints connecting these three or four-joint sections of the stem are equipped with tapered screw joints similar to those used on cable tools, except that they have a cylindrical hole through their longitudinal axis for passage of the circulating fluid. They consist of two parts, one shaped with a "pin" and the other with a "box." On the opposite or outer end of each part, a recess tapped to receive the threaded end of the drill pipe is provided. The several forms of tool joints differ from each other chiefly in the type of thread used. The Hughes tool joint has a modified square thread on the tapered joint. The Mack tool joint uses the buttress type of thread. Ordinary tool joints are provided with U. S. Standard or flattened 60-deg. V threads (see Fig. 77).

In normal use the tool joint threads are subjected to rough treatment. The lower pin on one stand is lowered by gravity into the open box on the upper end of the pipe already in the well, a process which results in abrasion of the threads unless unusual care is taken. In order to facilitate the frequent screwing and unscrewing of the tool joints, the threads are "doped" with heavy oil or grease.* The joints are partially tightened by hand with heavy pipe tongs (see Fig. 109) and finally tightened by application of power with the aid of a rope from one of the cat heads on the draw works.

Grief Stems.—In order that the rotary table may have a positive grip on the drill stem, the first 28 or 45 ft. below the swivel consists of a specially designed "grief stem" or "kelly joint" of angular form designed

* A lubricant suitable for use on rotary tool joints is made by the following formula: tallow, 33 per cent; white lead ground in oil, 23 per cent; graphite, 3 per cent; cylinder oil, 41 per cent.

to fit a similarly shaped opening in the rotary table. The grief stem is usually square in cross-section (see Fig. 63), though hexagonal and cruciform shapes have also been used. A cylindrical hole is provided through the grief stem for the passage of the circulating fluid and there is a pipe thread joint at each end for connecting by means of suitable collars with the cylindrical drill pipe and the rotary swivel.

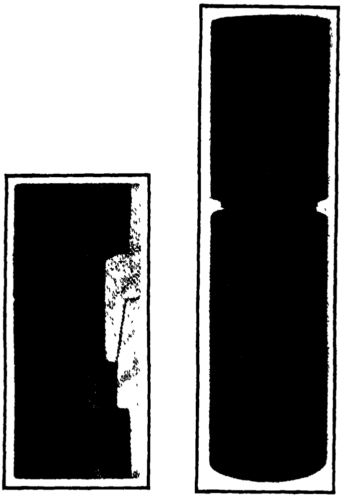


Fig. 77.—Types of rotary tool joints.

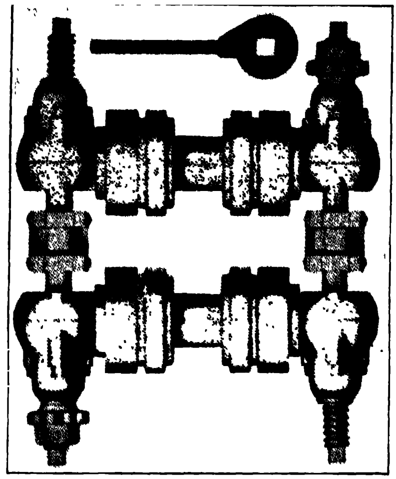


Fig. 78.—Grip rings for rotary table.

Earlier models of rotary tables were equipped with a gripping device for the cylindrical drill pipe, so that the use of a special grief stem was unnecessary. The gripping device consisted of two pair of steel rollers so mounted in sliding blocks controlled by heavy screws, that their corners could be clamped against the pipe (see Fig. 78). While this type of gripping device served its intended purpose, the corners of the rollers scored the pipe heavily, weakening it to some extent, and the screws controlling the position of the rollers required frequent tightening. It is still used to a limited extent, particularly in handling the smaller sizes of drill stem and in rotating casing.

The rotary swivel, which provides a means of pumping the circulating fluid into the rotating drill stem, and from which the latter is suspended while in the well, is illustrated in Fig. 79. It consists of a number of parts, all of which are contained within, or supported by a massive trunnion and bail. The upper portion of the trunnion block contains a gooseneck, to which the armored hose leading from the pumps is connected. The heavy tubing connecting with the drill stem turns with the latter, a collar being provided on the upper end of it, which rests on roller bearings to reduce friction. A ball bearing is also provided between the revolving and stationary portions of the swivel to take up the thrust that may at

times cause considerable pressure between the two parts. Several stuffing boxes are provided to prevent leakage, and there is an elaborate lubricating system which keeps the moving parts and friction surfaces within the swivel immersed in oil. When properly assembled and lubricated, there is practically no leakage of either water or oil from the swivel, and the lower portion attached to the top of the drill pipe turns freely and yet without any appreciable tendency to twist the cables of the hoisting block on which it is suspended. A complete swivel for a 4-in. drill pipe will normally weigh about 1,000 lb.; that used on a 6-in. stem, about 1,400 lb.

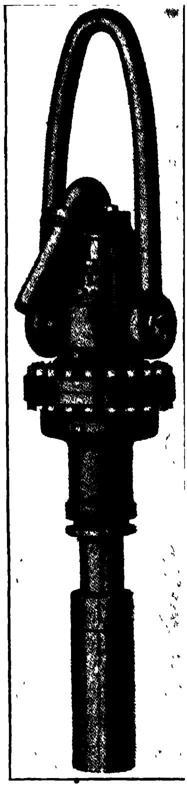


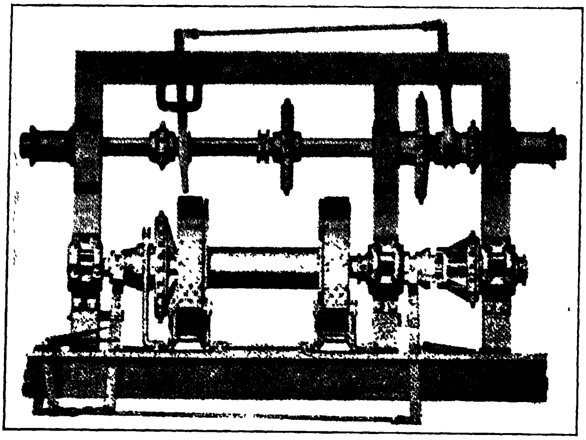
FIG. 79.—Rotary swivel.

The hoisting block (see Fig. 63), which supports the swivel, usually contains four sheaves (occasionally three and sometimes five), so that as many as nine lines may be threaded between it and the sheaves at the derrick crown. This provides a mechanical advantage of nine in favor of the draw works hoisting drum, on which the free end of the cable is wound. At times, however, for light service, a fewer number of lines with correspondingly greater hoisting speed may be used. The hoisting block is also used in inserting and handling casing in the well. A large hook suspended from the lower end of the block by a C-shaped link engages the bail of the rotary swivel or the links of the casing elevator. The hook must be suspended well below the center of gravity of the block, otherwise there is a tendency for the block to turn over when subjected to a heavy load.

The hoisting cable is similar in construction to the steel casing lines used in cable drilling (see page 111). The 1-in. and ⅞-in. cables are commonly used. A 1,200-ft. cable is long enough for use in a 106-ft. derrick, with 9 lines strung between the crown block and the hoisting block.

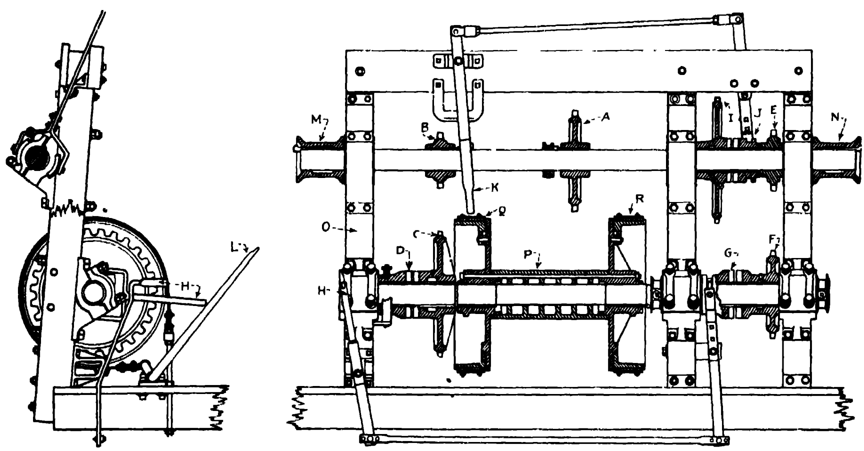
The draw works serves as a power distribution center for all power-driven parts of the rig except the pumps (see Fig. 80). It consists of two principal parts: the hoisting drum with its shaft, supporting boxes, sprockets, clutches and brakes, and the drive shaft with its supports, several sprockets, two cat heads and clutch. Both shafts are supported at different elevations above the derrick floor, by means of three heavy oak posts bolted to one of the main side panels of the derrick and to the derrick sills. It will be noted that the two shafts are mounted on opposite sides of the supporting posts, thus partially equalizing the bending stresses.

The functions of the several parts of the draw works have already been described in a general way on page 146. With reference to Fig. 81, *A* is the sprocket which receives the power by chain drive from the engine.



(*Union Tool Co., Torrance, Cal.*)
FIG. 80.—Rotary draw works.

B and *C* are sprockets connected by a chain belt, which, when connected with the hoisting drum through clutch *D*, revolve it at the lower of its two speeds. Sprockets *E* and *F* and clutch *G* give the hoisting drum its high



(*Redrawn with additions, from Union Tool Co.'s descriptive booklet*).
FIG. 81.—Rotary draw works.

speed. These clutches, operated by levers *H*, are so spaced that as one is thrown out of gear, the other is thrown in, with a neutral position between in which the hoisting drum is disconnected from the power. Sprocket *I* drives the rotary table, and is thrown in and out of gear by clutch *J*,

which is controlled by lever K. Brake lever L controls the movement of the hoisting drum when it is under tension from the weight of the drill stem and the power clutches are disengaged. M and N are cat heads useful in applying power to various small objects within the derrick. particularly to the wrenches used in setting up the tool joints on the drill stem. The driller stands at post O, within easy reach of the brake and clutch levers. A "telegraph wheel" also on this post, with an endless wire strand to the throttle valve of the engine, gives convenient control of the power. Another sprocket is occasionally placed on the drive shaft to operate a mechanical mud mixer, though this device is not ordinarily a part of the rotary equipment.

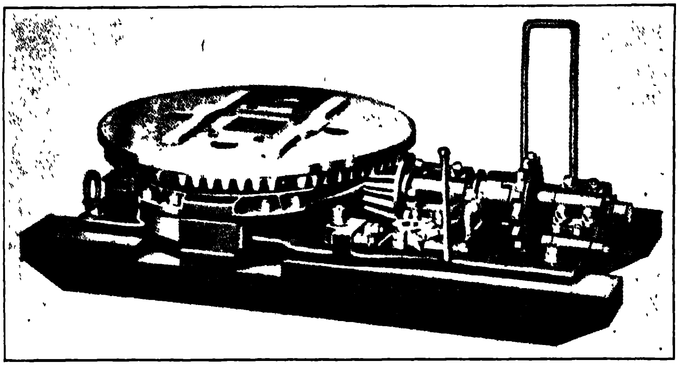
The gear ratios on the sprockets driving the hoisting drum are 12 to 28 for the low-speed drive and 12 to 20 for the high-speed. Hence the faster of the two hoisting speeds is 1.4 times that of the lower. The actual speed in either case, of course, depends upon the speed of the engine, which is variable within wide limits. A recent model is equipped with an additional pair of gears and clutch for a third speed, useful particularly in drawing out the drill stem. The drum P, on which the hoisting cable is wound, is about 16 in. in diameter and has flanges ranging between 34 and 42 in. in diameter, which provide braking surfaces for two powerful band brakes, Q and R, each about 8 in. wide and lagged with hardwood or asbestos blocks. The brakes are controlled by lever L, which may be clamped to lock the brakes, with a chain attached to the derrick floor. An automatic spring suspension device prevents dragging of the brake bands on the drum flanges when the brake lever is released.

The weight of the hoisting drum with its shaft, clutches, sprockets, brakes and boxes, varies from about 2,500 lb. for the lighter rigs, to as much as 7,200 lb. in the larger sizes. The line shaft with its equipment weighs about 1,600 lb. The larger sizes of draw works are designed to meet all the requirements imposed in handling drill stem and casing to a depth of 5,000 ft. For handling heavy casing at greater depths than this, or even at lesser depths when a light draw works is in use, a calf wheel is sometimes provided, similar to that used with the standard cable rig, and operated by a chain drive from the line shaft, or by a separate engine.

Occasionally also, a bailing drum is attached to the hoisting drum shaft, with a separate clutch and brake. This is useful in bailing mud out of the well on its completion, or when testing oil or gas sands for production, and is also an advantage in certain fishing operations. If a "combination rig" is used (see page 186), bailing facilities and a calf wheel will be provided as a part of the cable tool equipment.

The rotary table, which revolves the drill stem, is operated by a chain drive from the draw works. Except in the case of the shaft-drive type of rotary described below, the power is transmitted directly from a sprocket

on the line shaft to a second sprocket on a short pinion shaft mounted at the side of the rotary table. The pinion shaft is supported by two bearings, and on one end of it there is keyed a beveled pinion which meshes with circular beveled gearing on the lower side of the table (see Fig. 82). The pinion shaft also supports a clutch controlled by a short lever, which permits of disengaging the power at the table when desired. A cast-iron



(Union Tool Co., Torrance, Cal.)

FIG. 82.—Rotary table, chain-driven type.

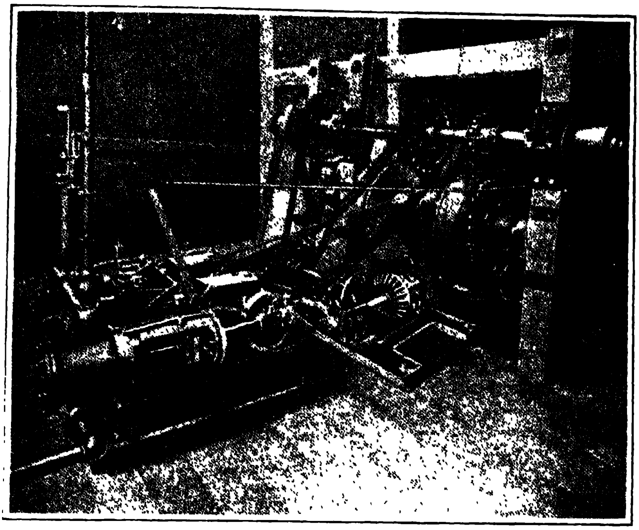
chain guard over the sprocket, and a ratchet locking device which prevents the table from revolving when screwing or unscrewing the drill stem, completes the equipment of the pinion shaft.

This arrangement of the power connections necessitates the use of a long chain extending nearly halfway across the free space within the derrick. Because of its exposed location, its high operating speed, the variable and often extreme strain imposed upon it and its susceptibility to breakage, this chain is a menace to the men at work on the derrick floor. Furthermore, it is an obstruction that prevents free passage about the rotary table, particularly in the process of screwing and unscrewing the drill stem.

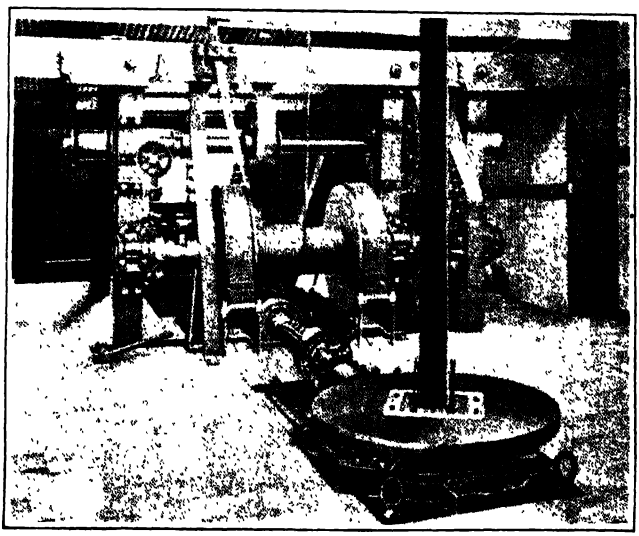
In order to avoid the use of this long drive chain, a more recent type of shaft-driven rotary has been developed which has met with widespread approval. In this, the pinion shaft is extended across the derrick floor and under the hoisting drum to a gear base located between the draw works and the engine (see Figs. 83 and 84). The gear base contains two beveled pinions which permit of revolving the drive shaft by a short pinion shaft mounted parallel with the line shaft of the draw works. A sprocket on each of the two latter shafts and a chain belt provide the necessary power connection.

The rotary table (see Fig. 85) consists of a heavy steel casting A, about 4 ft. in diameter, with a smooth flat top, and with beveled gearing, B, cast into the lower side. There is also cast into the lower portion of the

table a groove, *C*, which serves as a raceway for the cone rollers, *D*, on which the table revolves. The cones, mounted in a circular groove in



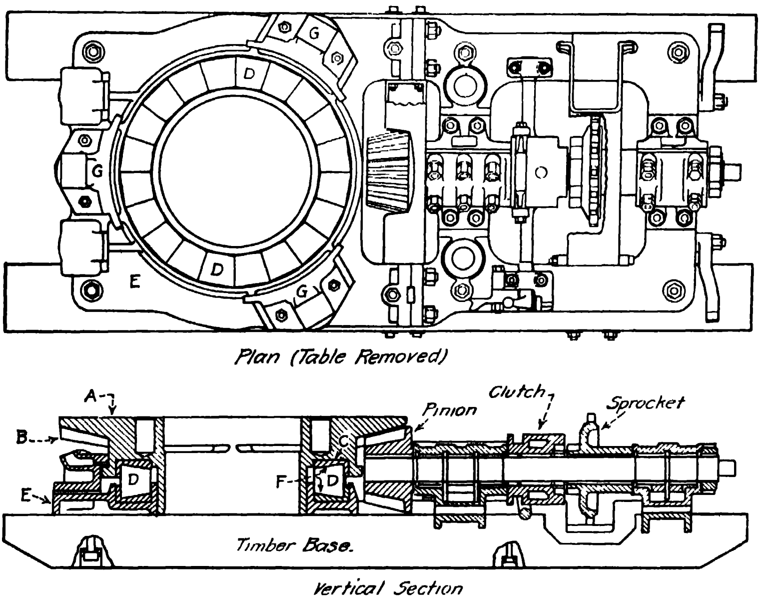
(*Union Tool Co., Torrance, Cal.*)
FIG. 83.—Drilling engine, draw works and gear base for shaft-drive rotary.



(*Union Tool Co., Torrance, Cal.*)
FIG. 84.—Shaft-driven rotary, showing draw works.

the metal base, *E*, revolve in a bath of oil automatically fed from oil reservoirs. The grooves in both the rotary table and the table base are

fitted with renewable flanged race plates, F, of high-grade carbon steel which furnish a housing for the cones and prevent wear on the heavier castings. The support for the pinion shaft is a separate casting securely bolted to the table base. To prevent the table from being lifted from its supports by the pinion when under strain, hold-down brackets, G, are provided which are bolted to the table base and project over a machined circular projection on the lower edge of the table. The metal base is bolted to a substantial timber frame which rests on sills below the derrick floor.

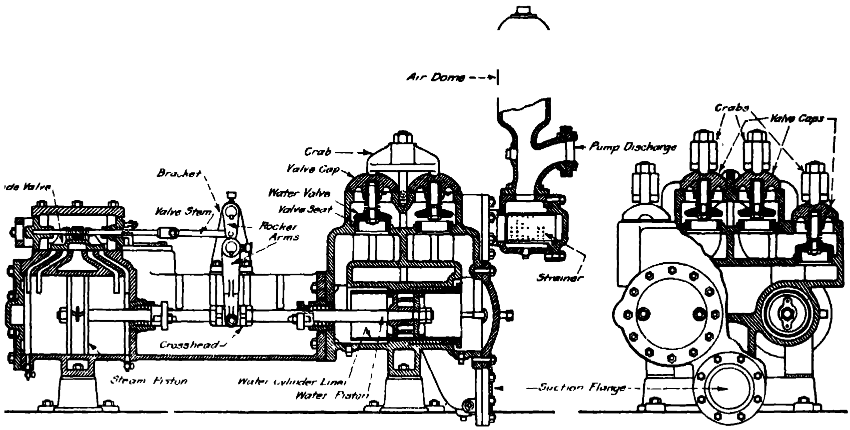


(*Redrawn with additions, from Union Tool Co.'s descriptive pamphlet*)
FIG. 85.—Chain-driven rotary table.

Through the center of the table an opening is provided for the passage of the drill stem. The form of this opening varies with the type of gripping device and table bushings adopted. A common type of table and gripping device utilizing the square grief stem has an opening which is square at the top and conical toward the bottom (see Fig. 82). It is equipped with a split bushing similar in form, which grips the square stem as the table revolves. For the conical portion of the opening there is also provided a set of circular slips for use on drill pipe or casing of all sizes up to the maximum for which the table is designed. Rotaries are rated by the size of the opening through the table, and vary from 19 to 27½ in. The size of this opening is also a measure of the maximum diameter of drilling bit that can be passed through the table, and hence determines the maximum diameter of hole that can be drilled.

A 20-in. rotary table and pinion shaft, complete with all of its parts, weighs approximately 6,500 lb. The 27-in. table weighs about 8,250 lb. The shaft-drive attachment with the additional pinions, sprockets and supporting castings, will add about 4,800 lb. to the above weights.

Rotary Chain Belt.—The sprocket chains that are used for transmitting power between the various parts of the rotary drilling rig are of substantial construction, and so designed that the chain may be readily broken or disengaged at any link. This is necessary in order to facilitate repairs or to adjust tension, or—in the case of the chain to the rotary table sprocket—to get it out of the way of operations on the derrick floor when it is not needed.



(*Redrawn with additions, from illustration in Lucey Corporation's Catalog No. 8*).
FIG. 86.—Sectional views of rotary slush pump.

The links are available in several different styles or patterns, usually made of steel, though frequently of malleable iron. In one type of chain that is commonly used the links are made of two separate side-bars fastened together at the joints with bushings or barrels and either rivets, bolts, pins or cotters. The bushings or barrels at the joints take up most of the wear and are easily replaceable. Another type is made of malleable iron, each link being cast separately in one piece, and the links later coupled together to form the chain.

These chains must be operated with considerable slack over the sprockets, otherwise they bind, make considerable noise and power is wasted in unnecessary friction. To reduce friction, noise and wear on the links and sprockets, the chains must be occasionally greased.

Slush Pumps.—The pumps used in maintaining circulation of fluid through the well are usually of the steam-driven, duplex, double-acting type, with removable steel cylinder liners and large valve areas on the water end to adapt them to use with thick muds, which may at times carry gritty sands. Because of the nature of the fluid handled, it is

important to have the valves, liners, packing glands and other wearing parts readily accessible for repairs. The steam valves are simple slide valves, positively controlled by rockers actuated by the pistons (see Fig. 86). The water suction and discharge valves are of the winged disc type, operating against heavy springs coiled about the valve stems. They are usually faced with rubber to insure tight seating. These pumps must be designed to operate under high hydrostatic pressures, occasionally as high as 800 lb. per square inch, though normal operating pressures do not exceed 150 lb.

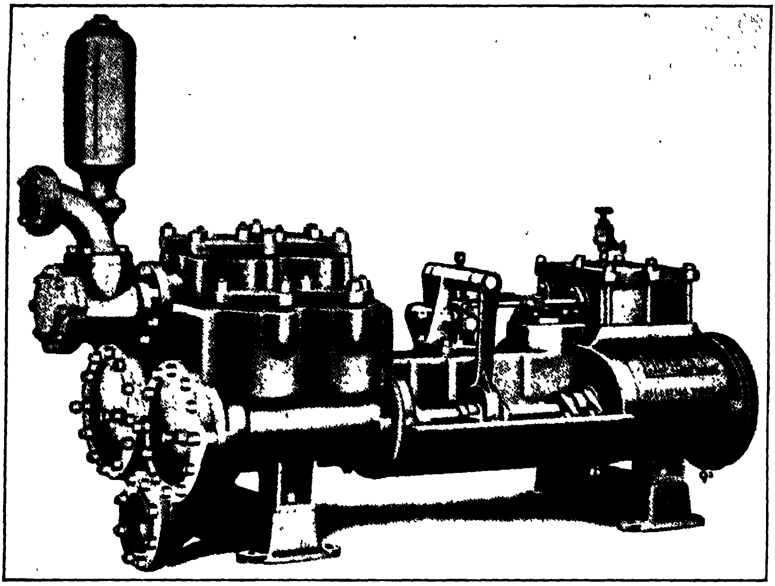


FIG. 87.—Slush pump for circulating mud fluid in rotary drilling.

Slush pumps are rated by the diameter of their cylinders and length of piston stroke. For rotary drilling service, the steam cylinders range from 10 to 12 in. in diameter, the water cylinders from 5 to 6¾ in., and the stroke is either 12 or 14 in. The 10- by 5¾- by 12-in., 10- by 6- by 12-in., 12- by 6¾- by 12-in., and 12- by 6¾- by 12-in. pumps are commonly used sizes. Capacities depend upon the operating speed, the resisting hydrostatic pressure and the efficiency of the pump. Normal pumping speeds will average from 30 to 40 at a depth of from 3,000 to 4,000 ft. but may increase to a maximum of 75 strokes per minute. The capacity of a 12- by 6¾- by 14-in. pump averages about 1 cu. ft. per revolution. Volumetric efficiencies (*i.e.*, actual delivery capacity divided by theoretical displacement capacity) may range as high as 85 per cent, but average about 60 per cent when pumping the heavy muds used in rotary drilling.[8]

Weights range from 3,400 lb. to as high as 6,900 lb. for the larger sizes of slush pumps.

The pump suction lines are usually of 6-in. pipe, equipped at the lower end with foot valves and strainers, well submerged in the mud pit. The suction lift should be as small as possible, and should never exceed 15 ft. To take up irregularities and induce a uniform flow in the discharge pipe, an air chamber is generally used on each pump. The delivery lines from the two pumps are manifolded to connect with the armored swivel hose. Quick-acting valves are provided in the pump manifold to permit of promptly changing the flow from one pump to the other when desired.

Rotary Hose.—The flexible connection between the slush pump manifold and the gooseneck of the rotary swivel consists of an armored hose of rubber and canvas, 2 or 2½ in. in diameter. The pressure to which it is subjected requires a hose of especially heavy construction. One commonly used brand is composed of eight thicknesses of fabric embedded in a rubber matrix throughout the greater part of its length, with ten-ply material at the ends. In addition, it is closely wound with heavy wire. Two 30-ft. lengths of hose connected by a coupling and two clamps are necessary to provide for the vertical movement of the hydraulic swivel.

MANIPULATION OF THE ROTARY EQUIPMENT IN DRILLING

Starting the Well.—With the rotary equipment completely rigged, with mud in the slush pit, steam in the boiler and all in readiness for drilling, a drilling bit of the size selected as the initial diameter of the well is securely screwed to a drill collar, and the latter on one end of the grief stem. To the top of this the rotary swivel is connected, which, in turn, is suspended from the hoisting block (see Fig. 63). The bit, collar, stem and swivel, connected as described, are then lowered through the rotary table into the conductor pipe until the bit is within a foot or so of the point at which drilling is to be started. Lowering of the drill stem is accomplished by partially releasing the brake on the hoisting drum, clamping the brake when the tools have reached the desired position. The driving bushings are then inserted in the table, one of the pumps is started and the table clutch thrown in. As the stem revolves, the hoisting drum brake is again released, and the tools are lowered until the bit begins to cut into the material in the bottom. The sludge soon reaches the surface and overflows into the mud ditch, which returns it to the slush pit after the coarse material has settled out. Frequently the drill collar will be fastened permanently to a joint of drill pipe by babbitting a recess left above the threads. In this case, it will not be possible to use the grief stem until the well attains a depth of 20 ft. or more, the

stem being rotated meanwhile by grip rings mounted on top of the table (see Fig. 78).

Adding a New Length of Drill Stem.—At intervals of 20 ft., as the hole is deepened, it will be necessary to add a joint of drill pipe to the stem. The slush pumps are stopped, the table clutch is thrown out of gear, the driving bushings are removed from the table and the stem is raised by applying power to the hoisting drum. As the joint at the lower end of the grief stem emerges above the table top, the drill pipe slips are placed in the table opening about the pipe, and the stem is lowered slightly until the slips take hold. The table is then locked so that it cannot revolve, and the pipe tongs are applied above the joint, aided by a jerk line from one of the cat heads on the draw works. When the joint has been loosened with the aid of the power, it can be unscrewed by hand, the three floor men of the crew grouping themselves about the stem and passing the tongs rapidly from one to another until the threads are disengaged. The grief stem and swivel are then hoisted until clear of the lower portion of the joint, then lowered and stood on end in one corner of the derrick, or lowered into a "rat hole" made by rotating two joints of 8-in. pipe under the derrick floor [8] The hook is then disengaged from the swivel bail, and the casing elevators placed on the hook in its stead. Meanwhile, a joint of drill stem has been brought into the derrick from the pipe rack with the aid of a casing carriage. The elevators are lowered, clamped under the collar on one end of the joint and the joint is raised until it hangs vertically in the derrick. After removing the protecting collar on the new joint of pipe, and doping the threads thoroughly, it is carefully lowered into the open collar of the portion of the stem supported by the slips in the table. Tongs are then applied to the new joint, first by hand methods and finally with the aid of the power, connecting a jerk line from the handle of the tongs to one of the cat heads on the draw works. When the new joint has been securely attached in this manner, the weight of the stem is transferred from the table to the crown block by hoisting the stem for a short distance and removing the slips. The stem is then lowered until the collar of the new joint is about 2 ft. above the table. The slips are again placed in position, and the stem lowered until the slips take hold. The elevators are then disengaged and removed from the hoisting block hook, before engaging the bail of the swivel. If the hook is large enough, the elevators may be left on the hook. The swivel and grief stem are then raised until clear of the derrick floor, swung to the center of the derrick and, after doping the joint, gently lowered until the lower end enters the collar on the upper end of the new section of drill pipe. Application of the tongs and slightly raising the stem until the slips can be removed from the table, completes the work. The pumps are then started, the stem is lowered until the bit is a few inches off bottom, the drilling bushings are placed back in the table and drilling is resumed. This procedure is followed with each joint of pipe added to the stem, except that at every third or fourth joint (depending upon the height of the derrick and the preference of the driller) a tool joint is used instead of the usual pipe coupling.

Replacing a Dulled Bit.—When slow progress indicates that the bit has become dull, the entire stem must be withdrawn from the well and unscrewed into "thrible" or "fourble" stands of three or four joints respectively; that is, the stem is broken at each tool joint. The pumps are shut down, the rotary table disengaged from the power and the tools hoisted until the joint at the lower end of the grief stem emerges above the table. This joint is unscrewed by application of the tongs as described above, the swivel and grief stem placed in one corner of the derrick, or in the "rat hole," and the elevators substituted for the swivel on the hoisting block hook. The elevators are next lowered until they can be clamped under the tool joint on the upper end of the stem projecting above the table. The stem is then

hoisted in the derrick until three or four joints of pipe have passed the table and the next tool joint emerges. The slips are dropped into place around the stem, the latter is lowered slightly until the slips take hold, the table is locked and the tool joint is broken. The disconnected section of drill stem, now suspended on the elevators, is swung over into one corner of the derrick and lowered until the lower end rests on the derrick floor. Meanwhile, the derrick man has been sent up into the derrick and has taken his place on the thrible board or fourble board (depending upon whether three- or four-joint stands are in use), which places him at an elevation level with the top of the stand. The derrick man guides the upper end of the stand into its position of rest against the fourble board or the thrible board, and disengages the elevators. The elevators are then lowered, a hold taken under the tool joint on the upper end of the next joint, and the process is repeated until the entire stem is disconnected and the bit emerges from the well.

With a skilled rotary crew, this work of drawing out and uncoupling the stem proceeds with clock-like precision. Each of the five men constituting the crew has a definite part to perform. The driller controls the engine, and the draw works clutches and brake. Three of his helpers work on the derrick floor about the rotary table in manipulating the pipe tongs, elevators and slips, and in swinging the lower end of the stands to their position at one side of the derrick. The part of the derrick man has already been described. As much as a thousand feet per hour of 6-in. drill stem, connected in 3-joint stands, can readily be withdrawn and uncoupled in the manner described, or at the rate of one stand every 3 min. A skilled crew can uncouple drill stem even more rapidly than this for short periods of time, but the work is tiring and fraught with some danger to the crew and to the equipment unless carefully performed. Hence undue haste is not encouraged.

When the bit emerges from the well, the table bushings must also be removed, and while out of their usual position, the opening through the table should be covered to prevent anything from falling through. The possibility of the bit dropping through the table opening as it is unscrewed from the drill collar must be guarded against particularly. After unscrewing the bit from the collar, a sharpened and properly gaged bit is substituted, and the new bit must then be lowered to bottom by coupling the sections of drill stem together again, a process precisely the reverse of that outlined above for withdrawing it. Each joint is "doped" before the stands are coupled together.

Drilling with the Rotary Tools.—As the rotary bit revolves on the "formation" in the bottom of the well, its effect will vary with the amount of pressure applied. If there is insufficient pressure on the bit, it will slide or drag over the rock face, loosening grains or fragments of material only occasionally, so that progress will be slow; the bit will be rapidly dulled and will lose its gage. If, on the other hand, too much pressure is applied, the bit will embed itself in the rock to such a depth that it cannot cut itself free, and will chatter up and down as it revolves. Excess of pressure on the bit throws so severe strain on the equipment at such times that breakage of the bit or a twist off of the drill stem is very likely to occur. Furthermore, the hole is apt to be crooked. With the proper pressure on the bit, the tool is forced to embed itself in the formation, just enough to permit of its chipping away the rock in small fragments as the stem revolves. Under such conditions there will be a minimum of grinding action and the maximum footage will be obtained.

It is apparent that the most effective pressure will vary with the character of the rock and the size of the bit, the harder rocks and the larger bits requiring the heavier pressures. Table XIV indicates recommended pressures for Hughes cone bits in three common types of hard rocks, and for a variety of sizes of drills. Being based on a straight-line relationship, the pressure can be reduced to a certain amount per inch of diameter, which varies from 1,000 to 1,600 lb. in the three type rocks listed. These figures are the result of experimental work on a large scale conducted by the Hughes Tool Company.

TABLE XIV.—RECOMMENDED BIT PRESSURES FOR USE WITH HUGHES CONE BITS*

Size of bit, in.	Revolutions per minute	Pressure to be placed on bit: Moderately hard sandstone, lb.	Pressure to be placed on bit: Hard lime, lb.	Pressure to be placed on bit: Granite or basalt, lb.	Gallons of mud per minute	Size of drill stem, in.
4¼	50–70	4,200	5,300	6,700	10	3
5¾	50–70	5,700	7,400	9,100	40	3
6¼	50–70	6,200	8,000	9,900	25	4
7¾	50–70	7,700	10,000	12,300	60	4
8½	45–65	8,500	11,000	13,600	85	4
9¾	45–65	9,700	12,600	15,500	130	4
10½	45–65	10,500	13,600	16,800	110	6
12	30–50	12,000	15,600	19,200	160	6
13¾	30–50	13,700	17,800	22,000	240	6
16	30–50	16,000	20,400	25,600	340	6
18	30–50	18,000	23,400	28,800	440	6

* From pamphlet published by Hughes Tool Co.

In the case of the commonly used fishtail bit, the heaviest duty will fall on the corners, the circular arc of movement of any point on the cutting edge increasing directly with its distance from the center of rotation. Furthermore, the corners are subjected to contact with the walls as well as with the bottom, and the wear will always be greatest at these points. Probably the bit always revolves with more or less eccentricity as a result of deflection of the drill stem, inequalities in the texture of the rock in the bottom of the hole or small differences in the form of the cutting wings.

With the usual rotary equipment, the driller can only guess at the amount of pressure on the bit and must base his control of the apparatus largely upon what his experience has taught him is proper for the particular hardness and kind of rock in which the bit is working, and for the depth and size of the hole being drilled. He is able to form some opinion of the

working pressure on the bit by the action of the drill stem and by the resistance to his downward pressure on the hoisting drum brake lever. He must adjust the speed of the engine to accord with the pressure applied and with the size of the bit used—a large bit under heavy pressure requires slow speeds, while with a small bit a low pressure or a rapid rotation of the drill stem produces best results. Drilling speeds range from 25 to 75 revolutions of the stem per minute.

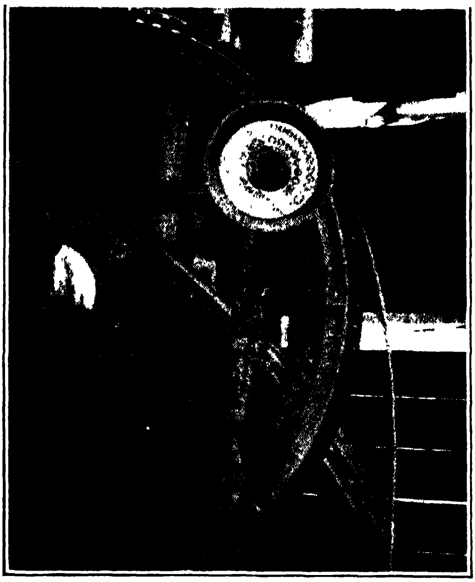


FIG. 88.—Hughes' weight indicator.

Computation of the weight of the drill stem at varying depths and comparison with the figures given for the proper pressure on the bit in Table XIV, indicate that at shallow depths the total weight imposed on the drilling tool will be somewhat below the pressure specified, while at greater depths the total weight of the stem will be greatly in excess of that necessary. The heaviest grade of 6-in. drill pipe averages approximately 30-lb. per foot, including collars and tool joints. A 6-in. swivel will weigh approximately 900 lb.; a 6-in. by 28-ft. square grief stem, about 2,900 lb.; a drill collar, say 150 lb.; and a 12-in. fishtail bit, about 200 lb. Adding these figures together, for a column of drill pipe with bit and equipment of the sizes indicated, we obtain a total weight at 250 ft., of about 11,400 lb.; at 500 ft., about 19,000 lb.; at 1,000 ft., about 34,000 lb.; and at 3,000 ft., upwards of 94,000 lb. These weights will be reduced about 15 per cent by the bouyant force of the fluid in the well, and to some extent also by contact with the walls of the well. Even if we

ignore these corrections, however, it will be apparent that there will be insufficient weight on the bit for best results when drilling in sandstone requiring a pressure of 1,000 lb. per inch of diameter (12,000 lb. for a 12-in. bit), even if the full weight of the stem is imposed, until a depth of something more than 250 ft. is reached. But at greater depths, the weight increases rapidly until at 3,000 ft. only about one-eighth of the weight of the stem should be permitted to bear on the bit. This means that the driller must so control the hoisting drum brake that seven-eighths of the load is borne by the crown block. It is apparent that a sensitive hand on the brake lever is necessary to bring about a proper distribution of load; good judgment in engine speed is equally important.

The Hughes weight indicator* has been designed with the purpose of giving the driller an actual measure of the weight imposed on the bit at all times. It is nothing more than a heavy spring balance attached to the dead line of the hoisting cable (see Fig. 88). The actual tension in the line to which the indicator is attached, of course depends upon the number of lines rigged between the crown block and the hoisting block. The dial is graduated to give direct readings in pounds pressure on the bit, for 4- and 6-line riggings. Simple calculations based on readings taken with the 4- and 6-line scales will give the pressures for any other number of lines. With 4 lines, a maximum of 50,000 lb. of drill stem can be weighed; with 6 lines, 75,000 lb.; with 10 lines, 125,000 lb. The accuracy of the apparatus when used intelligently under field conditions is within 5 per cent.

THE CIRCULATING SYSTEM AND ITS CONTROL

Much depends upon a proper control of the circulating system in rotary drilling. Prompt removal of the material loosened by the drill, proper mudding action on the walls to prevent caving, and on high-pressure gas and water sands to prevent "blow-outs," and a reliable record of the formation penetrated by the drill—all are matters of prime importance which depend upon satisfactory operation of the circulating system.

The circulating medium, as we have seen, is a mud-laden fluid which, under the propulsion of powerful pumps, flows down through the drill stem, sweeps under the bit and carries the drill cuttings to the surface through the annular space between the walls of the well and the drill stem. At the surface it overflows into a wooden flume in which the coarse material is settled out, before the mud is again taken up by the suction for further circulation through the well. During its passage from the bottom of the well to the surface, the mud sweeps over the rock surfaces forming the walls of the well, penetrates small fissures and pore spaces between the grains of porous rocks, depositing clay in these openings, thus effectively preventing admission of high-pressure gas and water to the well and giving greater stability to the walls. It is evident that in

* Manufactured by Hughes Tool Co., Houston, Tex.

these processes results will vary with the nature and consistency of the mud-laden fluid, with the rate of flow and with the pressure applied.

Mud Mixing Methods.—The source of the mud to be used in circulating the well, and the method of preparing it, must receive careful attention. Not all clays will serve the purpose—at any rate, some kinds are better than others—and if best results are to be obtained the clay must be thoroughly mixed with water to form a fluid of fairly uniform characteristics. Furthermore, there must be a considerable surplus of both water and clay ready for use in case of necessity for replacing fluid lost by absorption, or for suddenly thickening the well fluid to "kill" a high-pressure gas sand.

Usually a clay of proper characteristics will be found in some near-by clay bank, and can be hauled in wagons or trucks to the site of the well; but occasionally it must be transported for a considerable distance. Often, if argillaceous strata are encountered in drilling, the well will furnish its own clay after a start has been made.

The clay may be mixed with the necessary amount of water by simply shoveling it into the mud pit and stirring occasionally with shovels or hoes, or it may be mixed with the aid of the drill by shoveling the dry clay into the well; but a better plan is to use one or another of the several types of mechanical mud mixers. These may be had from the oil well supply dealers in the form of a wooden box equipped with either a vertical or horizontal paddle shaft, driven by a chain from a sprocket on the line shaft on the draw works (see Fig. 89). The equivalent made up of odds-and-ends to be found around any oil property is easily assembled. Some operators mix mud with steam jets placed in the mud pit or in a specially constructed mixing box, in such a way as to violently agitate the fluid. Laboratory tests have shown steam-mixed muds to have a slower rate of settling than mud mixed by mechanical devices.*

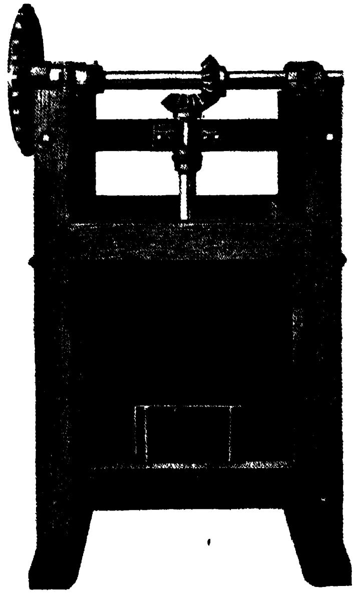


Fig. 89.—Mud mixing machine.

The mud ditch is usually a wooden launder about 2 ft. wide and 100 ft. in length, built around two sides of the derrick, with several right-angle turns. The joints are filled with pitch or asphalt to prevent leakage. The greater part of the length of the ditch is about a foot deeper than the outlet, thus allowing space for the accumulation of sand. The slope should be only about 1 ft. between the two ends, so that the mud flows sluggishly. A recent improvement in design provides large rectangular settling boxes at each right-angle turn. The mud discharges directly into the mud pit, a timber-lined pit with vertical walls, about 8 by 12 ft. in cross-section and 5 to 6 ft. deep. Frequently an ordinary mud pond with sloping earthen embankments is used for storage of fluid. The screened ends of the pump suction lines are well immersed in the fluid in the pit.

* Fagin, V. A., and Vance, H. J., Uses and properties of mud-laden fluids in rotary drilling, a *Thesis* prepared under the direction of the author, University of California, May, 1923.

Removal of sand from the fluid after it leaves the well and before it is returned to the mud pit is essential for best results. Sand in the fluid pumped into the well causes wear on the pump linings and valves and on the drill stem, is instrumental in freezing casing and drill stem and greatly reduces the plasticity and wall-building properties of the clay. While the mud ditch is fairly effective in removing the larger particles of sand from the fluid if kept clean, much of the finer sand passes through the ditch into the mud pit and is returned to the well. Some operators avoid difficulty as a result of this, by occasionally discarding the fluid and mixing new, but a more economical plan would seem to be to devise a means of effectively removing the sand. One California operator has developed a revolving cylindrical screen, placed over the mud ditch, through which all fluid must pass, the screen being revolved by the fluid. Efforts have also been made to adapt the sorting tube and hydraulic classifier used in ore dressing operations to the work of separating the sand from the mud.

Physical Properties of Mud-laden Fluid Used in Rotary Drilling.—The muds used in actual practice vary widely in the percentage of clay and in the physical properties of the clay. The type of clay best suited to the work is one which has a slow rate of settling, a high specific gravity and a low viscosity. These conditions are best fulfilled by an unoxidized (gray, blue or green) clay, free from sand or other coarse material. Some clays when mixed with water apparently possess colloidal properties and remain in suspension for long periods of time without appreciable settling. Nevertheless, a large percentage of solid may be present, and the specific gravity of sand-free mud may range as high as 1.45. It is found that these colloidal clays are more finely divided than ordinary clays, and for the amount of solids contained have an unusually high viscosity. Coarse sands therefore settle less rapidly and effectively in such mixtures than through ordinary muds. A small amount of alkali added to the clay-water mixture will greatly increase its colloidal properties, while acids and neutral salts have the reverse effect.[2]

Careful tests made on typical mud-laden fluids used in rotary drilling in the California fields have shown specific gravities ranging in most cases from 1.10 to 1.25 (9½ to 12 lb. per gallon) and Engler viscosities ranging from 1.3 to 4 at 20°C. Increase in temperature has but slight effect on the viscosity of these mixtures, tending to reduce the viscosity somewhat. In general, oxidized clays (red, yellow and brown clays) are found to settle at a more rapid rate than the unoxidized material, though there are apparent exceptions to this statement. The unoxidized clays also have a much greater absorptive capacity for water, and it is suggested that this property of clay in the dry condition be used as a means of selecting one clay in preference to another for rotary drilling purposes. Typical tests show good clays to have 30 times the absorptive capacity of poor clays. Some good clays will absorb more than 2.5 times their dry weight of water.*

At times when it is necessary to deal with unusually high pressures, the amount of solid clay pumped into the well may exceed the amounts indicated above, but in such cases the surplus solid material settles rapidly and is not regarded as a permanent part of the mud fluid. The fluid may, of course, be thickened temporarily to any desired degree by stirring more clay into the fluid in the mud pit, the only limitation being that imposed by the ability of the pumps to handle the mixture.

Action of the Mud-laden Fluid on Porous Rock Faces.—The extent to which the mud fluid will deposit clay on the rock walls of the well will depend upon the percentage of clay present in the fluid, its colloidal condition, the rate of flow, the pressure and the condition of the walls. It has been shown in the previous section that a certain proportion of the clay tends to remain in permanent suspension, and this ordinarily

* MONTGOMERY, C. H., and CHRISTIE, L. G., Properties of mud-laden fluids, a *Thesis* prepared under the direction of the author, University of California, 1920.

will not be deposited. Any clay deposited on the walls of the well must be in addition to the amount which remains permanently in the fluid. Accordingly, when it is particularly desired to deposit mud on the walls of the well, the driller thickens the fluid in the mud pit. More clay must be continually added if the mudding process is to be continued, for the fluid will soon drop its surplus clay and come to a condition of equilibrium. It should be noted that the volume of clay necessary to plaster the walls of the well will vary directly as the diameter of the hole. That is, the wall area exposed, per foot of depth, in a 12-in. hole is double that of a 6-in. hole. Deposition of mud on the walls of the well is greatly aided by the plastering action of the eccentrically revolving drill stem.

The amount of clay carried by the fluid in this condition of equilibrium varies with the nature of the clay (as explained above), and also with the rate of flow. The amount of clay that may be carried in the well fluid without deposition increases as the velocity of flow increases, a factor directly dependent upon the speed and capacity of the pumps and upon the cross-sectional area between the drill stem and the walls of the well. It follows that if heavy deposition of clay is the object sought, the speed of the pumps must be reduced until a suitable rate of flow is attained. If a slush pump delivers 100 gal. of fluid per minute through a 6-in. stem working in a 10-in. hole, the rate of flow as the fluid ascends through the well will be about 44 ft. per minute. With a 4-in. stem in a 7-in. hole and the same delivery capacity of the pump, the rate of flow will be about twice as great. The fluid will carry a much higher percentage of clay at the higher speed without deposition than at the lower. By varying the speed of the pumps, a nice adjustment of the rate of deposition to suit any condition imposed is possible.

The pressure maintained upon the fluid is also a factor in determining the rate of deposition, since it is only by excess of pressure in the well fluid, in comparison with that in the formations penetrated, that the fluid is able to enter the formation. When drilling in porous rocks, there is a measurable loss of volume in the well fluid which can only be accounted for on the assumption that the porous rock has absorbed the lost volume. When mud is absorbed by the formation, the clay undoubtedly follows the water into the crevices and pores of the rock to some extent. As it does so, however, the openings through which the mud flows gradually become clogged, until eventually they become impervious to the passage of fluid and the formation is effectively sealed. The extent to which clay penetrates the rock will undoubtedly vary with the porosity of the rock and the excess of pressure applied. Experiments conducted by Knapp[3] indicate that the mud is deposited primarily on the wall surfaces and that penetration seldom exceeds 1 or 2 in. Tests made by the Standard Oil Company of California,[2] however, have shown a penetration of as much as 12½ in. with a pressure of 1,200 lb. per square inch. In close-grained rocks, the clay deposit is probably almost entirely on the rock surface, but with the more porous rocks it seems reasonable to expect that it penetrates to a distance of at least several inches. In strata thought to be traversed by well-developed channels, the mud has in some cases appeared in wells several hundred feet distant from that into which it was pumped, proving that a considerable and fairly rapid migration through the formation is possible under favorable conditions. Loss of fluid during circulation is a direct measure of the pressure conditions within, and the porosity of, the strata penetrated; and drillers are in the habit of watching the depth of fluid in the mud pit as an indication of the nature of the rock in which the drill is working.

Effective application of the circulating fluid in controlling high-pressure gas, oil and water sands encountered in drilling depends not only on its ability to seal the pores of the rock, but depends also upon the hydrostatic pressure that can be applied to prevent a blow-out. Here density of the fluid is important, the hydrostatic head at any depth increasing directly with the specific gravity of the fluid.[5]

The use of mud-laden fluid in controlling high-pressure wells is to be discussed in greater detail in Chap. X.

The pressure which must be applied by the pumps to maintain circulation through the well is a measure of the resistance to flow encountered. This increases directly with the depth of the well and with the volume of fluid pumped, and inversely with the cross-sectional area between the stem and the walls of the well through which the fluid must flow. The actual pressure developed at the pump will seldom exceed 150 lb. per square inch, and the maximum volume of fluid handled will be about 300 bbl. per hour.

Action of the Circulating Fluid in Removing Material Loosened by the Drill.—Effective action of the circulating fluid in removing the drill cuttings depends chiefly upon its rate of flow, but also upon its density and viscosity, and the density and size of the material loosened by the drill. A sand particle tends to sink in water at a rate which increases with its size and density, the rate of sinking being an expression of the difference between the weight of the sand particle and that of an equal volume of water. In mud, the particle will sink more slowly because of the greater density and viscosity of the fluid, but its movement is still governed by the same physical laws. If now we are to raise this falling particle by giving upward motion to the fluid through which it is sinking, it is obvious that we must circulate the fluid at a more rapid rate than that at which the particle sinks, and that the net upward movement of the particle will be represented by the difference between these two rates of movement. Hence, when the circulating fluid in the well ascends with the cuttings from the drill, the latter are constantly sinking through the well fluid, but they rise to the surface because the fluid rises more rapidly than the cuttings sink. It is clear, however, that small particles will rise more rapidly than large particles of the same specific gravity, and that for particles of the same size, those having the lower specific gravity will have the more rapid rate of upward movement. In other words, the circulating fluid exercises a selective action on the material loosened by the drill, and it is conceivable that at a certain rate of circulation, with variable sizes of particles in the well, the coarser and heavier material might remain in the well, only the lighter and finer particles reaching the surface.

While this action of the fluid is altered to some extent by eddying or jetting through restricted openings, it should be recognized as a factor in calculating the time necessary for samples of a particular stratum to reach the surface (see page 179), and in determining the speed of the pumps necessary to keep the bit free from sludge.

Rate of Progress in Rotary Drilling.—The footage advanced within a given period of time when using the hydraulic rotary equipment will depend chiefly upon the character of the formations penetrated, the diameter of the well and the type and condition of the bit used. With the fishtail bit, drilling in an 11-in. hole in soft sandstones, a progress of from 100 to 200 ft. in 24 hr. is not unusual, and under exceptionally favorable conditions, when drilling in soft clays and shales, as much as 300 ft. have been drilled in one day. The footage advanced will vary with depth because of variation in the time spent in withdrawing and replacing the drill stem in changing bits. Figure 57 indicates conservative average rates of progress with rotary tools in the oil fields of California. With the Hughes cone bit, drilling in hard limestone, footages of 15 to 18 ft. per hour have been attained. The ability of the bit to hold its cutting edge is an important matter in relation to drilling speed,

on account of the time consumed in replacing a worn bit. The average speed that can be maintained over a period of weeks or months depends upon other matters than the efficiency of the drilling bit, and is often considerably less than the figures given above would indicate. Perhaps 40 ft. per day for depths up to 2,000 ft. would be an approximate average rate for all conditions met with in practice. Occasional fishing jobs are to be expected, and casing and cementing operations often interrupt the drilling routine for a time. In spite of such interruptions, however, it is not uncommon in the San Joaquin Valley region of California to complete a 2,500-ft. hole in less than a month from the time drilling is begun.

Identifying Formations and Gathering Log Data with the Rotary Equipment.—The rotary driller recognizes changes in formation by the action of the drill stem, the rotary table and the circulating pump. On withdrawing the drill stem from the hole, evidence concerning the nature of the material penetrated is also to be gained from the condition of the drilling bit. An examination of the drill cuttings brought to the surface by the circulating fluid and deposited in the mud ditch will indicate more definitely the lithological characteristics of the material in the bottom. Table XV gives the mechanical reactions and physical appearance of the circulating fluid for each type of rock ordinarily encountered in sedimentary formations.*

Progress in depth is estimated by the movement of the drill stem through the rotary table. The length of rotary drill pipe below the rotary table is definitely known at all times by steel tape measurement, and the grief stem is usually marked at 12-in. intervals as a further aid for the driller in determining the depth at which each change in character of the formation is encountered.

In order to correlate the samples obtained from the circulating fluid with the mechanical reactions of the drill, it is necessary to determine approximately the time necessary for the circulating fluid to transport material from the bottom of the hole to the surface. This is a function of the speed and delivery capacity of the mud pump, the depth and diameter of the hole and the diameter of the drill stem. The delivery time may be computed with fair accuracy if these variables are known, and can be readily checked by placing a quart or two of red paint or some distinctively colored dye in the pump suction and noting the time necessary for it to travel through the drill stem and back to the surface. The time necessary to reach bottom—which must of course be deducted from the round trip time to determine the delivery time from the bottom to the surface—can be definitely determined if the delivery capacity of the pump, the length and internal diameter of the drill stem are known.

* Collom, R. E., Prospecting and testing for oil and gas, U. S. Bureau of Mines, *Bull.* 201, p. 101, 1922.

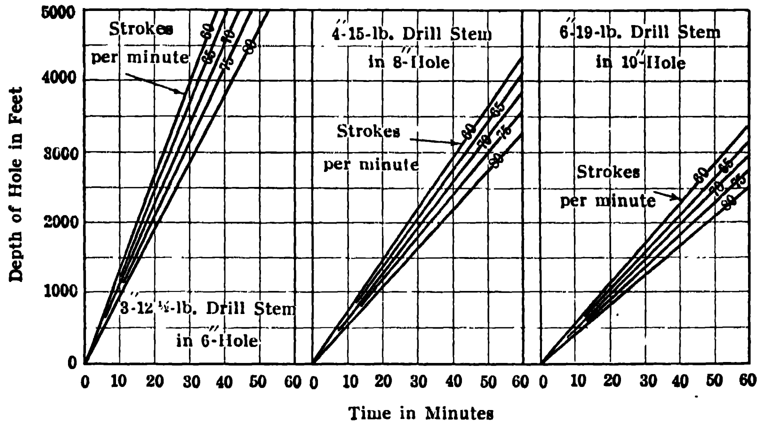
TABLE XV.—MECHANICAL REACTIONS AND PHYSICAL APPEARANCE OF THE CIRCULATING FLUID FOR VARIOUS SEDIMENTARY ROCKS IN THE PROCESS OF ROTARY DRILLING*

Field and formation	Action of pump and tools	Cuttings	Effect on bit
Midway Field, California:			
Hard sand...	Pump runs with low pressure, sand takes some fluid; tools jump.	Sand shows in ditch with thin mud.	Bit badly worn with only 1½ hr. drilling in hard sand.
Loose sand	Pump runs with low pressure; frequently takes mud; necessary to thicken fluid; when bit is stopped and set on bottom, sand can be sluiced out with mud stream, causing tools to plunge.	Sand shows in ditch with thin mud.	Does not cut bit appreciably.
Sandy shale.	Pump runs with low pressure; digs like sand, but with bit set on bottom cannot sluice out any hole below it.	Fragments in ditch with thin mud; streaked samples on tools	Cuts bits considerably.
Soft shale.	Pump runs with medium pressure.	Small fragments in ditch; soft chunks on bit, with streaks upon breaking	Cuts bit very little.
Hard shale..	Pump runs with more pressure than in sand; tools jump	Shows in ditch in small flakes and chunks, very little sticks to bit.	Cuts bit badly.
Clay......	High pressure on pump, run thin fluid; pump sometimes stalled; machinery runs smoothly with tension on table and chains; necessary to spud tools in order to clean the bit.	Change of color is the only showing of clay formation in the ditch; plenty of clay sticks to the bit.	Does not cut bit.
Shell	Pump runs freely; tools, chains and tables jump	Small fragments show in thin mud in ditch.	Cuts bit badly.
Sea shells	Pumps run freely, unless in clay.	Fragments and some perfect specimens show in ditch.	Do not cut bit.
Northern Louisiana fields			
Hard rock .	Pump runs slowly with low pressure.	Cuttings show in ditch in thin mud.	Wears bit badly and to all shapes.
Hard shell. Hard limestone.... Sand (hard and soft).	Run without much steam pressure; cuttings easy to handle	Cuttings show in thin mud in ditch.	Wears bit badly and to all shapes.
Shale	Run with nearly full head of steam, pumps handle cuttings without spudding but have to work hard	Fragments show in ditch	Does not wear bit appreciably.
Gumbo.	Run pump with full head of steam; even then continual spudding needed to mix cuttings enough to allow free returns.	Will ball up and shut down pump; no show except color in ditch	Does not wear bit appreciably
Chalk .. .	Run pumps with full head of steam; does not ball up; sometimes have to spud.	Small fragments of hard chalk in thin mud	Does not wear bit badly; hard streaks wear bit.
Gypsum	Does not take much steam pressure; pump can be run slowly; gypsum balls up on point of bit and retards progress, but has no effect on pump	Shows in flakes or small particles in thin mud; balls up on bit.	Does not wear bit appreciably
Salt...	Drills slowly; returns not hard to handle; no effect on pump.	Small particles occasionally.	Does not wear bit appreciably.
Southern Oklahoma:			
Shale, various colors	Tools run smoothly, medium pump pressure; drills fast.	Fragments show in thin mud.	Does not wear bit appreciably.
Sandy shale..	Tools run smoothly, chain "settles down;" drills fast	Fragments show in mud like shale.	Wears bit more than shales
Gumbo	Tools run in jerks; high pump pressure; hard to drill; driller has to reverse engine and spud tools to clean bit.	No show in ditch other than color; sticks to tools	Does not cut bit.
Clay.... .	Tools run smoothly; easy drilling; high pump pressure.	Balls up on bit; no sample in ditch other than color	Does not wear bit appreciably.
Limestones .	Tools jump and jerk when cutting; low steam pressure; hard to drill.	Fragments in ditch occasionally	Wears bit and reduces its gage.

* After R. E. Collom in U. S. Bureau of Mines, *Bull.* 201.

Actual delivery times vary from a few minutes to as much as 2 or 3 hr. (see Fig. 90).

The mud ditch through which the well fluid flows from the well to the sump in which the surplus is stored, is usually equipped near its upper end with riffles or depressions which serve to settle out and impound the coarser material. Samples useful in identifying formations may readily be secured by shoveling some of this coarse material from



(*After J R Suman and R. E. Collom*)

FIG. 90.—Time required for cuttings to reach surface when using a $5\frac{3}{4}$-inch by 12-inch duplex pump, operating under 60-per cent efficiency.

the ditch and washing thoroughly with clear water to remove the mud. If an uncontaminated sample from the stratum in which the bit is working is desired, drilling is stopped but circulation is continued until no more cuttings are brought to the surface. The mud ditch is then shoveled out and drilling is resumed. At the expiration of the calculated time necessary for cuttings to reach the surface, they are looked for in the mud ditch. Some drillers use a large-size thread protector (from the open end of a joint of casing) in the trench as a means of impounding a sample. Color plays an important part in the identification of materials in the mud ditch. Clays and shales will usually be so finely pulverized by the drill that the color imparted to the circulating fluid by them is the only means of identifying one stratum from another.

In some kinds of material, particularly clays and shales, drilling for a few minutes without circulation of fluid will ball up a mass of pulverized cuttings on the bit which is brought to the surface when the drill stem is drawn out.

Because of the rapid progress made in soft formations, and the difficulty of recognizing slight changes in the nature of strata penetrated, the rotary method does not yield so reliable and complete a log as the churn drilling method. A body of rapidly alternating layers of shale,

sand and clay, for example, will usually be logged as a single stratum of sandy shale; that is, the rotary drill logs show fewer formation changes, and seemingly thicker beds. Mechanical difficulties in operation of the drill will often be interpreted as due to hard rock. The "bowlders" commonly found in rotary logs, for example, are in most cases, formed artificially by the action of the drill on hard strata and on bodies of shale.

Rotary Core Drilling and Sampling Devices.—Uncertainty in the identification of finely pulverized returns from rotary drilled wells, so important in securing data for the well log, has led to the development of rotary core drilling devices, which secure either an uncontaminated sample or an actual unbroken core of the rock formation from the bottom of the well, so that it can be brought to the surface and closely examined. Most core drills are slow and somewhat unreliable in their action, and hence they are used only at such times as positive information concerning the material in the bottom of the well is desired.

Two general types of coring devices are in use, one of which cuts and removes a solid core from the formation without disturbing the natural arrangement of the rock strata, while the other simply removes a mass of drill cuttings uncontaminated by mud and well fluid. The latter is more properly termed a "sampling device." The former type is preferable since it gives better information concerning the rock structure and the dip of strata.

Some coring devices extract a solid core 7 or 8 ft. in length, but a core from 6 to 24 in. long and 2 to 3½ in. in diameter will be adequate for most purposes. After cutting out a core of the desired length, the core drilling tool is removed from the drill stem and the ordinary form of drilling bit substituted. In a deep hole, the taking of a core will consume from 10 to 14 hrs., most of this time being consumed in "drawing out" and "running in" the drill stem. Because of the time lost in drilling progress, core sampling is expensive.

While many different patterns of core sampling devices have been developed, they are very similar in general form and mode of operation. One of the simplest types that is commonly used consists of a piece of casing about 3 ft. long, on the bottom edge of which V-shaped notches or teeth are cut, either by machine methods or with the aid of the oxyacetylene torch. The teeth may be "set" slightly to maintain clearance, both on the inside and outside of the barrel.

The core barrel is screwed to the drill collar in place of the rotary bit, and is rotated on bottom until it has penetrated the formation to a depth equivalent to the length of core desired. As the core barrel is revolved and the teeth cut into the rock in the bottom of the well, the loosened material is forced upward into the barrel and retained by its frictional contact. When the desired sample has been drilled, the drill stem is raised a foot or two and dropped on bottom, thus bending the teeth inward to prevent the core from falling out of the barrel as the tool is withdrawn to the surface.

When taking cores in hard rock, which are apt to be loose in the core barrel, some drillers drop small pieces of cast iron into the drill stem. On slightly raising and lowering the barrel a few times on the core, the iron fragments become lodged between

the barrel and the core, holding the latter securely while it is broken off and withdrawn. Adamantine or chilled shot may also be dropped to the bottom before core drilling is begun, or pumped down through the drill stem, to aid the bit by their abrasive action in cutting the rocky formation.

Fig. 91 illustrates a formation sampler that has been successfully used by the Gulf Production Company in preference to all others.[8] The cutting end is equipped with a pointed lip, forged on the end of the core barrel as shown in the illustration. It excavates soft material in much the same manner as an ordinary post hole auger. In drawing out the tools, the lip prevents the sample from falling out of the barrel. Holes must be provided in the swaged nipple and in the drill stem above the back pressure valve, to allow the circulating fluid to escape from the stem and from the barrel.

In the simpler forms of sampling devices the core barrel must be slit on a planer or with the oxyacetylene torch, in order to extract the sample. Either method of course destroys the core barrel, so that a new one must be used for each sample taken. The heat generated by the oxyacetylene torch is occasionally sufficient to alter the appearance of the sample, so should be avoided if other methods of removing it are available.

Of the many devices designed for securing actual solid cores of the formation penetrated by the well, none appears as yet to have received general approval, and none stands out as distinctly superior in action to others. In the case of hard rock, the problem of coring is relatively easy, and unbroken cores of considerable length are readily obtained. Softer and less thoroughly cemented rocks do not usually yield a continuous, unbroken core of any great length, and the material withdrawn in the core barrel is in many cases in no better condition for examination than it would be if taken with the sampling devices described above.

The Okell rotary core barrel, which has been used with some success in securing large cores from the soft formations of the California fields, consists of a plain piece of pipe with one or more grooves cut in the lower end at an angle of about 45 deg. with the vertical axis.[7] Small fragments of steel are used as an abrasive in cutting the core, the angular slots continually carrying the abrasive material from the sides of the hole to the cutting edge.

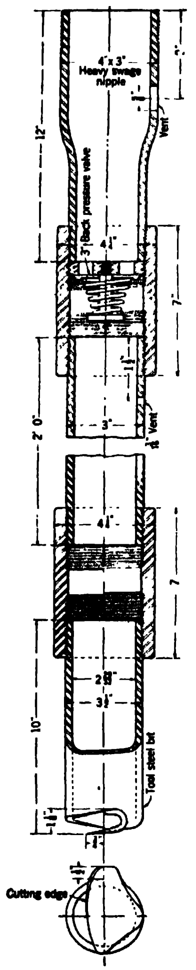
Some operators have been using a device for coring soft formations, in which the core barrel is incorporated in the center of a fishtail bit; that is, the fishtail bit is bored out at the center of rotation to receive a core barrel which may extend through the shank of the bit and as far into the drill stem as the length of core desired may require. The Knapp core barrel is of this type (see Fig. 92). This device* consists of a fishtail bit, *A*, with shank bored out to receive the core barrel, *H*, which is made of 2- to 4-in. pipe. The bit is connected to the drill pipe, *C*, by a drill coupling, *B*. A special drill coupling, *D*, supports and swivels the core barrel, and is provided with vent holes to equalize pressure on the core. The tube *E*, leading to the core barrel, is retained in position by a shoulder *F* in the bit, and by a ring, *G*. The core barrel, *H*, is swaged to fit a smaller sized coupling at its upper end, the latter being also connected with a swivel pipe, *K*, supported by a ball bearing ring, *L*. A stuffing box, *O*, and back-pressure valve, *J*, prevent the circulating fluid from entering the core barrel, forcing it to flow through perforations in the coupling, *D*.

A California oil company has developed and successfully applied the coring device illustrated in Fig. 93.† This consists of a crown bit with replaceable teeth, attached to a heavy shoe, which is in turn connected by a substantial steel pipe to a

* Collom, R. E., Prospecting and testing for oil and gas, U. S. Bureau of Mines, *Bull.* 201, p. 119.

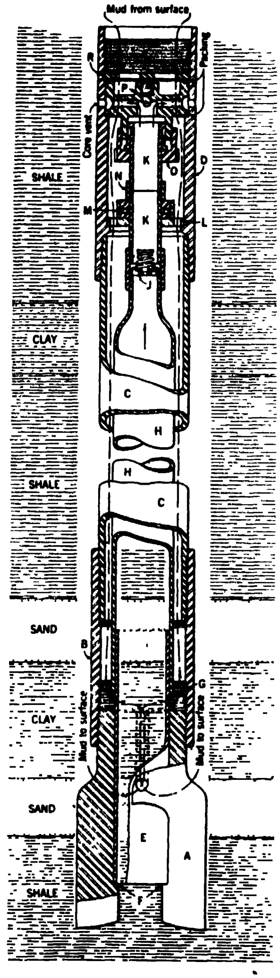
† The Elliott and Spengler core barrels, widely employed in the fields of southern California, are of somewhat similar type.

drill collar on the lower end of the rotary drill stem. An inner core barrel, supported between shoulders on the shoe and drill collar, receives the core, and split corrugated slips supported in a recess in the shoe immediately above the bit prevent the core from falling out. A relief valve at the upper end of the core barrel permits fluid to escape into the drill stem as the core enters. Circulating fluid passes



(*After J. R Suman and R E. Collom*)

FIG. 91.—Sampling device used by Gulf Production Co.



(*After R E. Collom in U. S B. Mines Bull 201*).

FIG. 92.—Knapp core barrel.

Explanation of key-letters used in Fig. 92

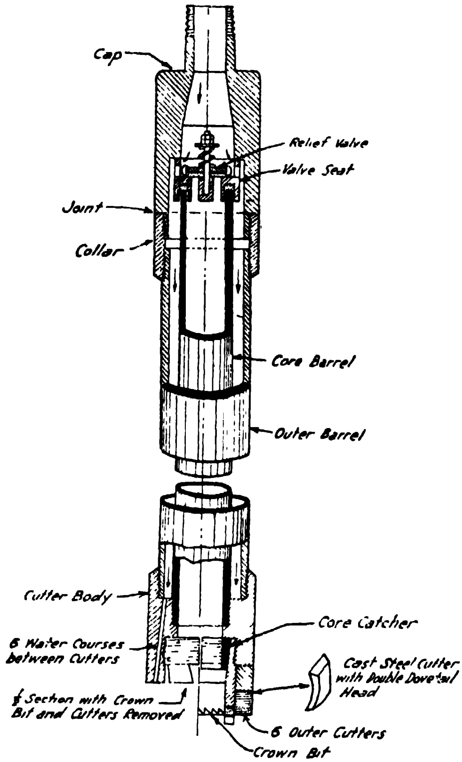
A = 6" fish-tail bit.
B = 6" drill pipe coupling.
C = 6" drill pipe
D = Coupling supporting and swiveling core barrel
E = 4" pipe forming lower end of core barrel
F = Shoulder in "*A*" to prevent "*E*" from falling through.
G = Ring preventing "*E*" from being forced upward.
H = Main core barrel of 4½" pipe swaged to 2½" at top.
J. = Back-pressure valve.
K = Swivel pipe
L = Perforated annular ring supporting core barrel
M = Ball bearing supporting core barrel.
N = Coupling supporting swivel pipe and core barrel.
O = Stuffing-box.
P = Head through which core barrel is vented to the ascending fluid.
R = A perforated follower holding "*P*" in place.

between the outer and inner tubes for the full length of the core barrel, and is discharged directly under the bit through the water courses provided, thus preventing overheating of the bit and core.*

* BARNES, R. M., Notes on core sampling in connection with rotary drilling, Summary of Operations, California Oil Fields, vol. 6, no. 12, p. 16, June, 1921. *Sixth Annual Report of the California State Oil and Gas Supervisor.*

The speed of drilling will largely determine the character of the core. The advance should be fairly rapid—from 2 to 6 in. per minute in most rocks. The full weight of the drill stem should not be permitted to bear on the cutting tool, except, perhaps, in drilling the last few inches, when it may be permitted to do so in the hope of plugging the lower end of the barrel with crushed material so that the core will not fall out as the tool is withdrawn from the well.

Some coring devices must operate under great pressure from the drill stem, and without the usual supply of circulating fluid, the fluid being permitted to escape from the stem in most cases through holes bored at some distance above the bit. This results in considerable overheating of the bit and of the core; often sufficient to vaporize any oil that may be present, and even to fuse some of the minerals.* This can only be prevented by drilling slowly and avoiding excessive pressure on the coring device. The hole must usually be under-reamed after coring.



(*After R E Barnes, California State Mining Bureau, Dept of Oil and Gas*)

FIG. 93.—"Oil Fields—Holland" core barrel.

COMPARATIVE ADVANTAGES AND DISADVANTAGES OF ROTARY AND CABLE SYSTEMS OF DRILLING

Having studied in some detail in the foregoing pages the equipment used and the methods employed in drilling by both the standard cable and rotary systems, the reader is now in a position to consider intelligently their relative advantages and disadvantages. There has been much discussion of this subject among people interested in the production of petroleum since the rotary method began to assume importance as a competitor of the cable tool system. During the earlier years of rotary drilling there was considerable distrust of the method, and numerous arguments were advanced against its use, chiefly by drillers trained in the use of the cable tools, who naturally disliked a process so radically different from that which had been used since the early days of the industry. At first the method was thought to be chiefly applicable to certain peculiar conditions prevalent in the fields in which it was first successfully applied,

* CASE, J. B., Notes on use of core barrel with rotary tools, Summary of Operations, California Oil Fields, vol. 7, no. 9, Mar., 1922. *Seventh Annual Report of the California Oil and Gas Supervisor.*

but as its use was extended to other fields and the records achieved by it became known, the rotary came to be accepted as a real competitor of the older method. Within recent years it has been gaining rapidly in favor, until today we find it used to some extent in almost every oil region in the United States, and in many fields it is now used exclusively. However, the cable tool method is still widely used, approximately 100,000 of the 109,000 wells drilled in the United States during the period 1914 to 1918 being drilled by cable tools. Improvement in design and the development of hard-rock rotary bits and rotary core drilling devices have been largely responsible for more extended use of the rotary equipment within the last 5 years.

When the two methods are impartially compared it is at once evident that the rotary has certain definite advantages that make it preferable under ordinary conditions. It is more rapid, and because of this it operates at a lower cost per foot and secures production within a shorter space of time. By its use, strings of large-diameter pipe may be carried to great depths with minimum loss of working diameter and at a considerable saving in the cost of casing. It has been found possible to drill through great depths of unconsolidated sands and shales with the rotary under conditions that are practically prohibitive for the cable tools. It is simpler—much of the technic that required years of experience for the cable driller to acquire is unnecessary in rotary drilling. To be sure, successful operation of the rotary equipment requires a technic of its own, but it will be generally admitted that it is easier to acquire the art of rotary drilling than to become a skilled cable driller. The rotary operates fairly continuously, without interruption for bailing, and with a fewer number and a smaller variety of fishing jobs. Use of the circulating fluid provides a means of controlling high gas and water pressures often encountered in drilling for oil, and makes possible the carrying of open hole to great depths; so that the well does not have to be cased until the particular size of hole being drilled is completed. Furthermore, there is greater freedom of the casing in the well, and the landing depths and water shut-offs can be more definitely planned and the work carried forward with greater certainty of completion according to predetermined schedules. Action of the cable tools is severe, often fracturing the walls so that they cave readily. The hole drilled by the rotary, on the other hand, is clean cut, with a minimum of fracturing of the walls, and the hole is necessarily always round so that the casing passes freely through.

While there is much to be said in favor of the rotary method of drilling, there are some disadvantages that favor the cable method under certain conditions. Probably the greatest disadvantage that can be urged against the use of the rotary is the difficulty encountered in determining the character of the formations penetrated. It is essential that accurate data for the well log be secured, and in many cases the drilling

returns brought to the surface in the sludge with the rotary equipment are so finely pulverized and contaminated with mud that they cannot be definitely classified. The color of the sludge, the presence or absence of sand and grit, effect of the formation on the bit and the manner in which the drill stem, table and mud pump behave, are about all that the driller has to work on in securing data for the log. With the sandstones and harder rocks it is possible to secure a fairly good sample which can be washed free of mud from the mud ditch, but the presence or absence of argillaceous material in the formation can only be surmised since it is usually so finely ground that it is inseparable from the circulating fluid when it reaches the surface. With the cable tools, on the other hand, it is possible to get a fairly definite idea of the nature of the rock in which the drill is operating by an examination of the material brought up by the bailer; and often large fragments of the material will be found adhering to the bailer or to the drilling bit when it is withdrawn. The disadvantage of the rotary in this respect promises to be overcome in the near future by the more general use of rotary core drilling devices which give the driller an actual sample of the material in the bottom as it occurs in place.

Another disadvantage frequently urged against the use of the rotary is that the circulating fluid used tends to seal off the sands encountered, commercial oil sands being sometimes mudded off so effectively that the operator drills through them without becoming aware of the presence of oil. This is a particularly serious criticism in the drilling of pioneer wells in a new field, or wherever the exact depth of the oil sands to be encountered is uncertain. Even in partially developed fields where the position of the productive sands is definitely known, the oil sand faces exposed in the well are frequently so clogged with mud that the well never attains normal productivity. Many irregularities in the productions of adjacent wells can be explained on this basis. Such difficulty, however, is largely due to unskilful drilling, or failure to sufficiently wash out the clay after completion of the well, and is therefore not a logical argument against the use of the rotary method. It is also claimed by some proponents of the cable method, that if the oil sands are under low gas pressure, considerable water may be permitted to enter from the well, partially flooding the sand and reducing its normal productivity. It seems probable, however. that the mudding action of the circulating fluid would prevent any great quantity of fluid from entering the oil sand. Furthermore, it should be readily drained from the area about the well by a few days of pumping after the well is completed.

While many drillers will question this statement, it is probable that rotary holes are more frequently crooked than wells drilled by cable methods. However, crooked holes may be largely eliminated by more careful drilling methods, particularly by the use of lower bit pressures.

Unless hard-rock bits are available, the rotary makes very slow progress in hard sandstones and limestones. The fishtail bit is rapidly dulled in such rocks and much time is lost in withdrawing and replacing the drill stem in changing bits. The cable tools may be withdrawn from a 3,000-ft. hole in 5 min., but 3 hr. are necessary to remove a rotary bit. Use of the Hughes cone bit and other hard-rock bits will partially offset this disadvantage of the rotary, however.

The rotary equipment has a greater first cost than a cable tool rig, and if the hole to be drilled is a shallow one, the additional cost of the rig will offset any advantage which the rotary may possess in reduction of casing expense or cheaper unit drilling cost. A standard cable rig has a much lower daily operating cost because of the fewer number of men employed, and because it requires less power; hence, unless the rotary equipment can show a marked superiority in footage drilled, its advantage from the standpoint of unit cost is lost.

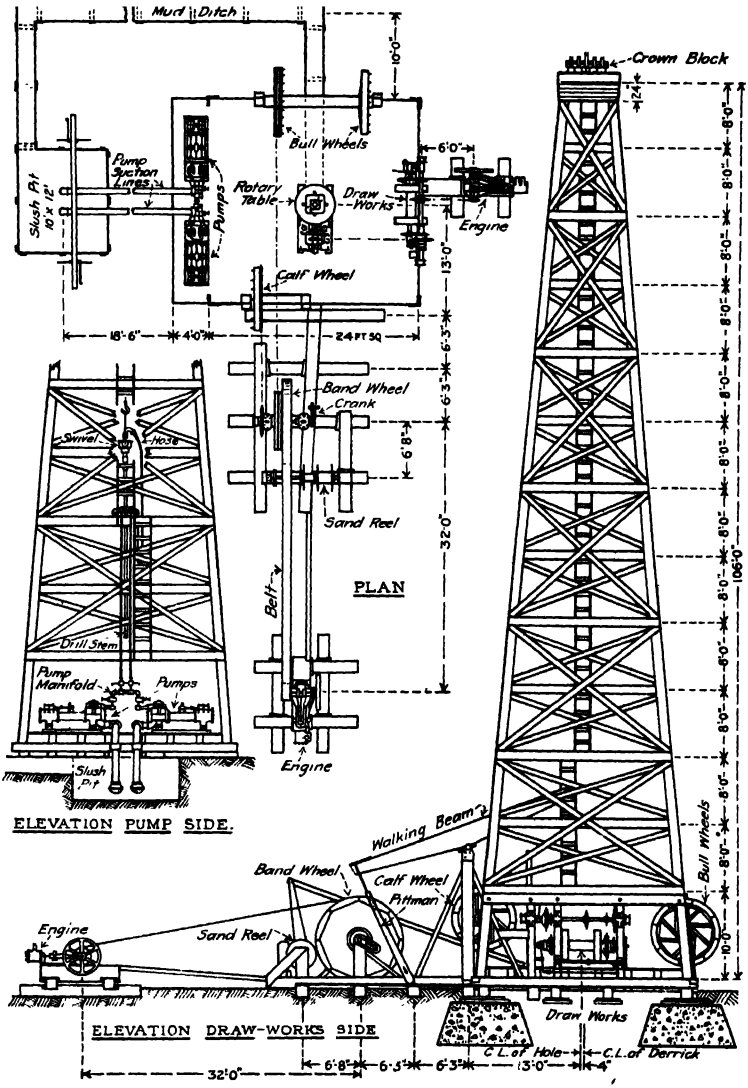
Water supply and transportation are troublesome factors in some regions. Here again the standard method has the advantage, the equipment being more readily transported and requiring considerably less water for drilling and steam-raising purposes.

Summarizing the arguments given above for and against each of the two methods of drilling, it would appear that the rotary method is superior when the oil-producing strata lie at considerable depth and their position is definitely known; when the formations to be penetrated consist mainly of soft and moderately soft rocks; and when formations containing high-pressure gas are expected. The standard cable method, on the other hand, is preferable in drilling "wild-cat" wells where the geological conditions and stratigraphic sequence are uncertain, and where accurate information for the well log is especially important. The cable tools are generally preferred if any great thickness of hard rock is to be penetrated, or where the productive horizons are found at shallow depths. Cable tools are often used in finishing wells drilled primarily with rotary equipment, particularly if the oil sands are under low pressure, because of the danger of mudding off the productive strata by use of the latter method.

Combination Rigs and Methods

With a view toward securing the best features of both the rotary and cable tool methods of drilling, many operators prefer what is called a "combination rig," which includes all the essential equipment pertaining to each of the two methods, under one derrick. The rotary equipment is then used when it seems best adapted to the conditions to be met, and when the cable tools are preferable they will be rigged and made promptly available. In some combination rigs, the rotary and cable tools are arranged to work simultaneously.

The usual form and arrangement of the combination rig is illustrated in Fig. 94. It will be noted that there is no change in the position of any of the parts of either the rotary or cable tool equipment. Two engines



(*Redrawn with additions, from National Supply Co.'s Catalog No.* 30).

FIG. 94.—Plan and elevations of California type combination rig, 106 ft. high.

Note: One or more platforms with railings (not shown in drawing) are ordinarily provided around the outside of a California derrick for the safety and convenience of the derrick man. The crown block is also customarily surrounded by a suitable platform and railing. See. Fig. 95.

are necessary if the two systems are to be used alternately, but in the California fields, where the combination rig is most used, it is usual to provide only one engine, only a short time being required to shift the

engine from one position to the other when a change in the method of drilling is desired. The cable tools can readily be operated through the opening in the rotary table, using the slips in the latter instead of a casing block. However, it is a simple matter to move the rotary table out of the way temporarily if necessary. One end of the hoisting cable may be attached to the hoisting drum of the draw works, and the other to the calf wheel shaft, so that the hoisting blocks may be raised or lowered from either end. The calf wheel is more powerful than the hoisting drum, because of its greater diameter and slower movement, and is therefore preferred in handling casing.

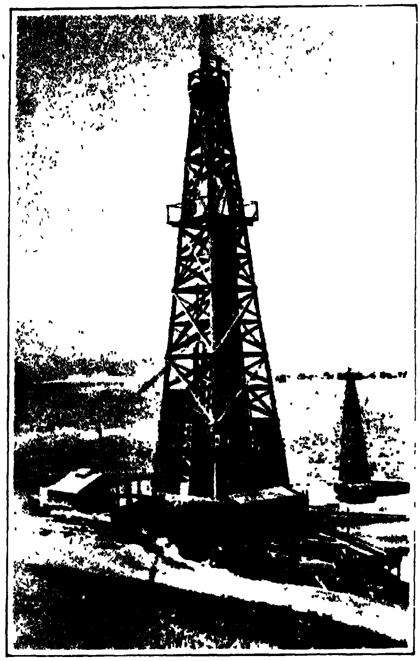


FIG. 95.— California type combination rig, 106 ft high.

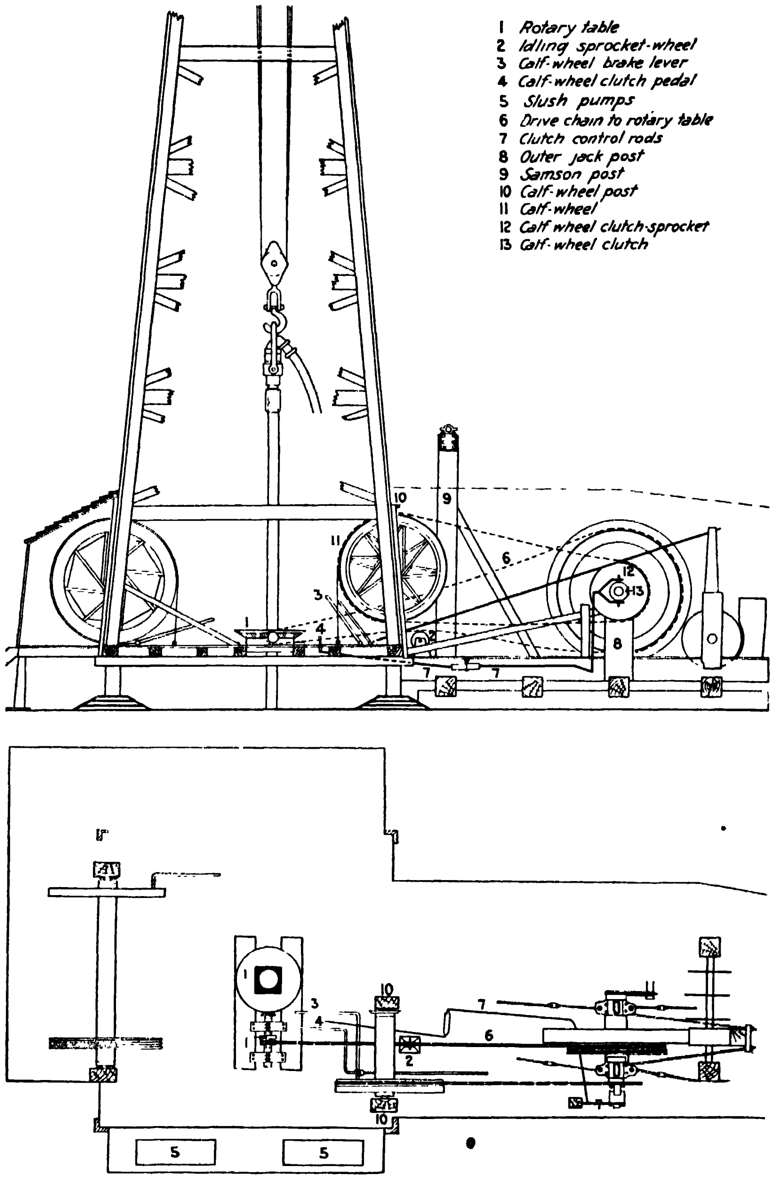
The derrick used is often 106 by 24 ft., the size generally employed in rotary drilling.* The requirements imposed by the rotary equipment determine the size and weight of the combination rig, a rig heavy enough for rotary drilling having ample strength for any strain imposed in cable drilling. However, it is customary to use a heavy derrick with ample bracing. Certain slight changes in the arrangement and number of the sheaves in the crown block are necessary.

Other arrangements of the equipment in a combination rig have been suggested and applied. One design places the draw works under the walking beam near the Samson post, driving the draw works by a chain from a sprocket on the band wheel shaft. In this case, one engine may be used and the calf wheel may be dispensed with, using the hoisting drum of the draw works to manipulate casing when either system of drilling is employed. Occasionally the Samson post is pivoted so that the walking beam may be swung to one side, out of the way of the rotary drill stem and swivel.

In another type of combination rig, known as the Parsons and Barrett rig, the rotary table is placed at the bottom of a 20-ft. cellar, and is used to rotate a string of casing, on the bottom of which a rotary cutting shoe is mounted. The casing is suspended on a swinging spider and the cable tools are operated on the beam through a swivel-jointed circulating head, somewhat similar to that described in connection with the standard "circulating" system. The circulating fluid used to remove the sludge overflows from the well in the bottom of the cellar and is carried off to a sump in a connecting tunnel. A small pump lifts the fluid from this underground sump to a mud pit on the surface. Two separate engines are necessary, one for the rotary

* Recent deep drilling in the fields of southern California has led to the use of higher derricks, 122 by 24 ft. being a common size.

table and one for the cable tools. Both the rotary shoe and the cable drilling tools are operated simultaneously at the same depth. The apparatus seems unduly complicated and expensive both in first cost and operating cost, and except for a possibly



(*After F. W. Ziegler, Cal St Mining Bureau, Dept of Oil and Gas*)

FIG. 96.—Light combination rig used for shallow drilling.

greater drilling speed, has no apparent advantages. So far as is known by the writer, it has not been employed on other than an experimental basis.

A method of adapting light rotary equipment to use under a 90-ft. cable tool derrick and rig has been developed in the Midway field of California.* The productive horizon in a portion of this field lies at a comparatively shallow depth (900 ft.), and consists of thick (350 ft.), loosely cemented sands very difficult to penetrate with the cable tools because of their tendency to cave. The rotary equipment is well adapted to drilling in this material, but the building of a rotary rig and derrick for the drilling of such shallow wells makes operations costly. In the method devised, the upper part of the well is drilled with the cable tools in the usual manner, until the overlying formations are cemented off immediately above the oil sands. A rotary table is then placed over the hole, with the sprocket side of the table toward the slush pumps (see Fig. 96). A calf wheel sprocket tug rim is bolted to the band wheel over the inside tug pulley, and is used to operate the rotary table by means of a long drive chain supported at the center by an idling sprocket wheel suitably mounted a short distance above the derrick floor. The engine is moved up close to the band wheel and the flywheel is removed, making the engine more sensitive to control and eliminating the jerky movement resulting from the use of a long belt. The drill stem is raised and lowered by a hoisting block rigged with three sheaves, both ends of the hoisting cable being attached to the calf wheel shaft, thus giving high hoisting speed. The calf wheel clutch is controlled by a foot pedal at the driller's position. Two slush pumps, a mud mixing tank and a settling trough are added to the cable tool equipment when the rotary table is to be used. Rigging the rotary equipment as described occupies a little more than 2 days of daylight work, for three rotary crews. A number of wells have been drilled with this equipment at a lower cost than is possible with either the standard or rotary methods operating alone, and the wells are completed in two-thirds of the time necessary with cable tools.

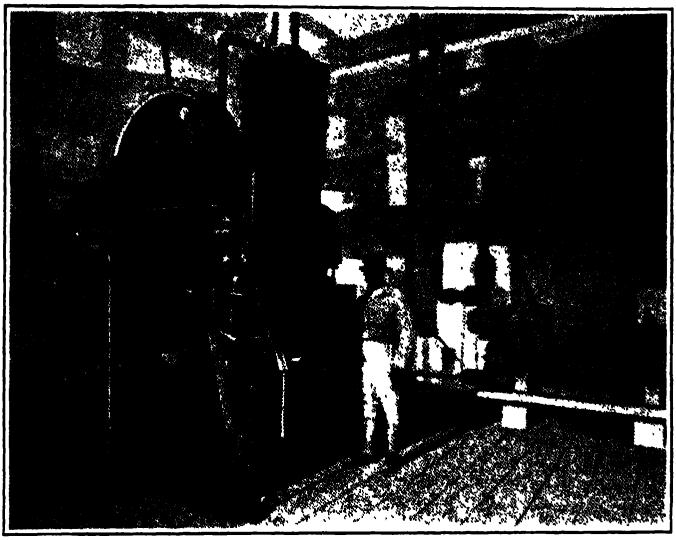
DIAMOND DRILLING FOR OIL

For many years, the diamond drill was considered inappropriate for use in drilling for oil, though it had found extensive use in prospecting for the metals, for coal and for other non-metallic products. Probably the chief reason for this belief was the fact that the earlier types of diamond drills were incapable of drilling holes exceeding 2 in. in diameter —too small for efficient oil production in the event that oil was encountered. In recent years the diamond drill has been further developed, and heavier models capable of drilling holes of larger diameter have been introduced and used to some extent in drilling for oil.

The diamond drill is equipped with an annular steel bit on the cutting edges of which are set a number of black diamonds (bort). The bit is mounted on the end of a drill stem made up of "rods" of flush-jointed, square-threaded steel tubing in 10-ft. lengths, and of a diameter somewhat smaller than the bit. The stem has a smoother surface and is more slender, in comparison with the hydraulic rotary drill stem. The drilling bit and stem are revolved at a speed of from 200 to 400 revolutions per minute by means of steam-engine driven, beveled gearing (see Fig. 97). The rods are gripped by a chuck which is free to revolve, and yet may be moved

* Ziegler, F. W., Method used by Chanslor-Canfield Midway Co. in drilling wells in the North Midway Oil Field, California, Summary of Operations, California Oil Fields, vol. 7, no. 7, Jan., 1922. *Seventh Annual Report of the California State Oil and Gas Supervisor.*

vertically either upward or downward by a direct-connected piston in a cylinder, actuated by hydraulic pressure. In effect, the hydraulic feed device is equivalent to an hydraulic jack which carries the weight of the rods and yet allows them to



(*Sullivan Machinery Co., Chicago*).

FIG. 97.—Sullivan diamond drill used in deepening 4,000-foot well, Signal Hill Field, Cal.

revolve freely. This apparatus gives a more positive and delicate control of the movement of the drill stem than is possible with the draw works of the hydraulic rotary. A small power-driven hoisting drum equipped with a steel cable aids in withdrawing the drill and stem from the hole, while a derrick, varying in height with the depth and size of the hole to be drilled, provides the necessary support for the hoisting sheave and for the rods as they are withdrawn.[10]

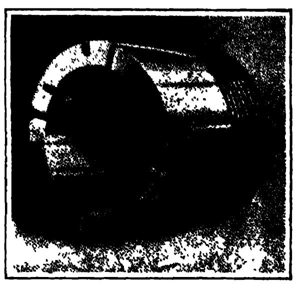


FIG. 98.—Diamond drilling bit.

Water is pumped down through the drill stem with the aid of a reciprocating, steam-driven pump and a swivel connection on the top of the stem. The circulating fluid flows out into the hole through the bit, and rises to the surface between the drill stem and the walls of the hole, carrying the pulverized drill cuttings to the surface and keeping the bit free of accumulated material. The bit is of such form (see Fig. 98) that it cuts a solid core out of the center of the hole, the resulting rock core being received and retained by a core barrel placed within the drill stem, just above the bit. When a depth of hole equal to the length of the core barrel has been drilled, the bit and rods must be withdrawn from the hole and the core removed. A complete series of cores of the formation penetrated may thus be secured. Pulverized material cut by the bit in maintaining its exterior and interior clearance is considerably finer than the cuttings obtained with the hydraulic rotary. Occasionally the diamonds in the bit must be reset or replaced by new stones, though with proper care the wear is slight in most sedimentary rocks.

The chief field of the diamond drill in the petroleum industry will probably be found in exploration and prospecting work, where geological information is desired rather than a well through which oil may be efficiently produced. Because of its speed and economy, the diamond drill offers what is often the most inexpensive means of determining whether oil is or is not present under a given location. Furthermore, it provides the geologist with an actual core of the rock formations penetrated, showing the material just as it occurs in place; and by proper measurements the cores may even be oriented with respect to the compass, so that the amount and direction of the dip of the strata may be approximately determined. Such information is invaluable in prospecting for oil. And when it is remembered that in this work many dry holes must be drilled for every one that results in discovery of oil, it is apparent that the loss which results through inability of the small-diameter diamond drill hole to produce oil economically is, after all, a small matter. Furthermore, the diamond drill hole may be reamed to a 50 per cent greater diameter at small cost if production is secured. The primary purpose of the wild-cat well is to secure information, not to produce oil, and if this principle is recognized, the diamond drill is probably better adapted to the work than any other, especially in the drilling of deep and moderately deep holes.

While it is generally conceded that the diamond drill is not well adapted to the drilling of oil wells in cases where a means of producing oil from a known oil deposit is the objective, there are notable exceptions which seem to indicate that under favorable conditions wells might be economically drilled for production by this method. For example, in the Panuco field of Mexico, a well was drilled with a diamond drilling outfit which was brought in with an initial production of 1,200 bbl. per day and subsequently successfully operated as a producing well.[9] The well was drilled to a depth of 2,153 ft. and was finished with a minimum diameter of $3\frac{5}{8}$ in. Gas pressures in excess of 750 lb. per square inch were encountered. The drilling speed, using the diamond bit in hard rock, averaged 75 ft. per day, but it is probable that double this footage could be maintained with a skilled crew and a longer core barrel than the 13-ft. barrel which was used. This well was completed in less than 90 days, though the average time of drilling to production in the district, with cable tools, is 5 mo. The cost was about 60 per cent of the current contract price in the field. About 85 per cent of the core was extracted. So successful was this experiment with the diamond drilling equipment in the Panuco field, that the Pánuco-Boston Oil Company, for which the well was drilled, immediately authorized the drilling of a second well by the same method. Other diamond drill holes have been drilled for oil in the fields of Canada and Burma and in the Argentine. Further testing of the method is being conducted in the fields of southern California.

THE COST OF DRILLING

The cost of drilling will vary widely, depending upon the depth and nature of the formations to be penetrated, the method of drilling used, the skill of the drillers employed, the diameter of the hole and the casing requirements. Costs are also largely influenced by fortuitous circumstances. The accidental loss or breakage of a tool in the well, or collapse of the casing, a blow-out of high-pressure gas resulting in loss of control or an unsuccessful water shut-off, may result in greatly increased unit costs. Cost data therefore are of little value for comparative purposes unless the complete drilling history of the well and a thorough description of the formations penetrated are made available. Published data on drilling costs seldom do this; indeed, few operators take the trouble to record such information.

The costs of labor, lumber, steel and other materials, of transportation, water and power supply are also important variables. Aside from regional variation, the unsettled commodity markets and readjustments in wage scales have had an important influence or drilling costs within recent years. The cost of drilling in 1920 was approximately twice that of 1913 in most American fields as a result of such changes (see Table XVI).

TABLE XVI.—COMPARATIVE UNIT DRILLING COSTS, 1913 TO 1920, CALIFORNIA FIELDS

Standard Cable Drilling Costs.—Cost in dollars per foot for 6 different properties operated by a large company in the Sunset (California) field. Average depth of wells about 2,000 ft.

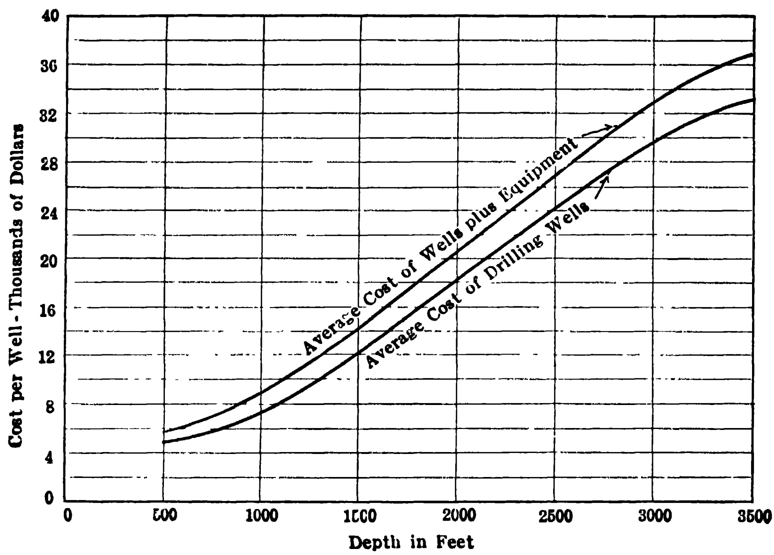
Property No.	Year							
	1913	1914	1915	1916	1917	1918	1919	1920
1	10 84	11 13	11.46	13 04	15 48	17 52	18 35	19 25
2	9 85	10 29	10 75	12 25	14 68	16.89	17.72	18 64
3	10.36	10 65	10 96	12 47	14 80	16.75	17.55	18 41
4	11.40	11 80	12 19	14 02	16 69	19 03	19.96	20.86
5	10.68	11.15	11 65	13 28	15 91	18.31	19 21	20 20
6	10 44	10.81	11 17	12 84	15 29	17 43	18 28	19 11

The figures given in Tables XVII, XVIII, XIX and XX, on the cost of drilling, must be regarded as representing merely the cost of particular wells under the conditions pertaining, and they should not be applied except in a very general way in estimating costs for other wells drilled, perhaps, under quite dissimilar conditions. It will be noted that casing

TABLE XVI.—COMPARATIVE UNIT DRILLING COSTS, 1917 TO 1919, CALIFORNIA FIELDS (*Continued*)

Rotary Drilling Costs.—Average costs for a large company operating in the San Joaquin Valley (California) fields.

District	Year	Total footage	Cost per foot	Cost of operating one string of tools for 1 mo.
Coalinga	1917	70,800	$16.00	$ 8,600
Coalinga	1918	80,400	21.20	11,100
Coalinga	1919	44,900	24.68	10,275
Sunset	1917	165,500	12.55	9,860
Sunset	1918	143,000	14 29	9,820
Sunset	1919	84,300	17 42	9,120



(*After M. L. Requa*).

FIG. 99.—Graphs showing average cost of drilling and equipping oil wells, San Joaquin Valley Fields, California, 1914.

is generally the greatest single item of expense in the cost of a well, while the labor cost and the cost of the rig and derrick are the only other items of comparable magnitude. Fig. 99 indicates the average cost of drilling to various depths for a group of several hundred wells drilled chiefly with cable tools, in the San Joaquin Valley fields of California prior to 1914. The lower of the two graphs represents the bare cost of drilling and permanent well equipment, while the upper graph includes also additional tankage, gathering lines, electrical equipment, etc.

A convenient method for roughly estimating drilling costs involves the use of per diem rates for operating expense, and average rates for drilling speed, cost of derrick and equipment and casing. Thus, for average conditions in the San Joaquin Valley fields of California, in 1920, the following approximate figures could be applied:

			Cable Tools	Rotary
Average cost of rig and derrick			$4,500.00	$5,750.00
Cost of operating rig, per day			52 00	118.50
	12½ in., 50 lb.	10 in., 40 lb	8¼ in., 32 lb.	6⅝ in., 40 lb.
Casing cost, per foot	$3 30	$2.45	$2.00	$1.40

The average time required in drilling to the estimated depth can be approximately determined from the graphs given in Fig. 57. The figures to be used, of course, would vary with the locality, and would have to be adjusted from time to time as commodity prices and wage scales varied.

Many operators find it profitable to have their wells drilled under contract, the contractor furnishing everything necessary except the rig and derrick, water, power, casing and fixed equipment. Under the contract, the well is drilled at a specified rate per foot, so that when this practice is followed, it is possible to estimate in advance the cost of the well to the producer with fair precision. It is also customary to contract cementing and well shooting jobs, in the former case at a flat rate per job ($250 in the California fields), the contractor furnishing labor and cementing equipment, and in the latter case at a certain rate per quart of nitroglycerin used. Rig building is often contracted to concerns or individuals specializing in such work.

A considerable part of the rig, drilling equipment, boilers, etc., may be salvaged when the well is completed, not being necessary after it is placed on production. Estimated first cost of the well may be reduced by from 10 to 15 per cent if such salvage is taken into consideration as is proper if the material and equipment removed may be used in drilling other wells, or has a definite sales value. If the well is a dry hole and the casings can be pulled and the engine, boilers, rig and derrick removed, a much greater reduction will result—often as high as 30 per cent of the first cost.

TABLE XVII.—COST OF DRILLING FOUR WELLS, COALINGA FIELD, STANDARD TOOLS, 1913*

	Depth of well			
	1,330 ft.	2,083 ft.	2,485 ft.	2,830 ft.
Derrick and rig:				
Labor, grading	$ 20.00	$ 15.65	$ 8.90	$ 20.00
Lumber, nails, bolts, etc	1,126.00	1,303.21	1,421.34	1,593.64
Rig irons	495.42	495.42	495.42	690.00
Teaming	137.75	72.20	66.38	150.00
Planing mill, material and labor (oak arms, cants, etc.)	85.50	84.55	111.60	126.25
Machine shop work on bolts and rods	1.80	2.75	7.60	12.50
Labor, building rig, including placing rig irons	265.00	265.00	295.00	250.00
Total, derrick and rig	$ 2,131.47	$ 2,238.78	$ 2,406.24	$ 2,842.39
Rigging up:				
General supplies, including lumber, line pipe, engine and boiler fittings, brick, lime, and sundry fittings	$ 678.71	$ 537.90	$ 533.43	$ 743.34
Teaming	87.90	61.00	87.67	100.00
Shop work	12.75	11.75	22.40	66.00
Labor	566.20	605.63	587.66	594.30
Total, rigging up	$ 1,315.56	$ 1,216.28	$ 1,231.16	$ 1,503.64
Engines and boilers:				
Maintenance covered by general drilling expenses charged below				
Removed on completion of well, and replaced by gas engine as below.				
Drilling:				
Belts	$ 87.73	$ 175.46	$ 228.27	$ 159.29
Bull ropes	44.20	65.50	69.30	63.68
Casing	5,316.73	8,562.50	10,481.10	13,567.84
General supplies	660.25	1,439.61	1,205.23	1,443.93
Machine shop work	142.45	363.95	318.60	447.55
Teaming	189.47	320.98	268.12	569.85
Labor (including installing tubing and pumps)	2,081.30	4,244.77	3,987.45	3,748.80
General drilling expense, including drilling lines, upkeep of tools, proportion of drilling superintendent's salary, etc	1,820.00	3,600.00	3,000.00	3,640.00
Total cost of drilling	$10,342.13	$18,772.77	$19,558.07	$23,640.94
Fuel:				
Natural gas used (no cost)				
Water	$ 120.00	$ 120.00	$ 180.00	$ 180.00
Gas engine:				
One 25 hp	665.00	665.00	665.00	665.00
Labor, installing and fitting	66.71	66.71	88.30	88.30
Total fuel	$ 731.71	$ 731.71	$ 753.30	$ 753.30
Labor:				
Removing steam engine and boilers	$ 20.00	$ 20.00	$ 20.00	$ 20.00
Tubing	400.30	400.30	799.20	799.20
Rods	122.40	122.40	243.00	243.00
Pumps	20.22	20.22	24.51	24.51
Tankage	327.50	327.50	327.50	327.50
Grand total	$15,561.29	$23,969.96	$25,542.98	$30,334.48
Total cost per foot	$ 11.70	$ 11.49	$ 10.28	$ 11.08
Actual working time (days)	80	160	149	175
Feet per day	16.6	13.0	16.7	16.2

* After R. P. McLaughlin in *Bull.* 69, California State Mining Bureau.

TABLE XVIII.—COST OF DRILLING WELLS WITH CABLE TOOLS

	Well No. 1		2		3		4		5		6	
Field	Ranger, Tex		Desdamona, Tex.		Caddo, La.		Lost Hills, Cal		Coalinga, Cal		Sunset, Cal.	
Year drilled	1919		1919		1919		1920		1920		1920	
Depth in feet	3,200		2,700		3,200		1,418		1,650		1,200	
Drilling time, days	60		50		60		79		100		50	
	Total	Per ft	Total	Per ft.	Total	Per ft	Total	Per ft.	Total	Per ft.	Total	Per ft.
Derrick and rig	$ 4,500	$ 1.41	$ 4,800	$ 1.78	$ 5,000	$ 1.56	$ 4,750	$ 3.35	$ 5,000	$ 3.03	$ 4,326	$ 3.61
Engine and boilers	†	†	†	†	†	†	695	.49	660	.40	275	.23
Tanks, sumps and flow lines	3,000	.94	3,000	1.11	3,000	.94	*	*	*	*	*	*
Fuel and water	1,200	.38	1,150	.43	1,400	.44	908	.64	2,277	1.38	450	.37
Drilling	13,450	4.20	13,050	4.84	16,500	5.15	3,106	2.19	4,191	2.54	2,475	2.06
Casing	16,476	5.14	13,899	5.14	16,720	5.23	10,663	7.52	13,695	8.30	4,867	4.06
Cementing	..	..	...	....	...	....	780	.55	412	.25	375	.31
Shooting	920	.29	920	.34	920	.29						
Hauling	1,000	.31	1,150	.43	3,400	1.06	950	.67	743	.45	275	.23
Overhead and incidental expense	4,055	1.27	3,842	1.42	4,704	1.47	893	.63	1,419	.86	1,064	.89
Totals	$44,601	$13.94	$41,811	$15.49	$51,644	$16.14	$22,745	$16.04	$28,397	$17.21	$14,107	$11.76

Well No 1: 82- by 22-ft. derrick; 6-in. rig irons; gas fuel; 350 ft. of 15½-in. 70 lb casing, 800 ft of 12½-in, 50-lb casing; 1,400 ft. of 10-in, 40-lb casing; 2,000 ft of 8¼-in., 32 lb casing; and 3,200 ft. of 6⅝-in., 24-lb. casing; 200 ft. of hard black lime requiring under-reaming; 200-qt. shot of nitroglycerin. Contract drilling at $3 per foot; black lime, $10 per foot.

Well No 2: 82- by 22-ft. derrick, 6-in. rig irons; gas fuel, 800 ft. of 12½-in., 50-lb casing; 1,400 ft of 10-in, 40-lb. casing; 2,000 ft of 8¼-in, 32-lb. casing; 2,700 ft of 6⅝-in., 24-lb. casing; 150 ft. hard lime; 200-qt. shot of nitroglycerin. Contract drilling at $4 per foot; black lime, $10 per foot.

Well No. 3: 82- by 22-ft. derrick; 6-in rig irons, gas fuel; 350 ft. of 15½-in, 70-lb casing; 800 ft of 12½-in, 50-lb casing; 1,400 ft. of 10-in, 40-lb. casing; 2,200 ft of 8¼-in., 32-lb casing; and 3,100 ft of 6⅝-in. 24-lb. casing. Contract drilling at $4 50 per foot

Well No 4: 82- by 22-ft derrick; oil fuel; 530 ft. of 13½-in. stove pipe; 950 ft. of 10-in., 40-lb. casing; 1,250 ft of 8¼-in., 28-lb. casing; 1,418 ft. of 6¼-in, 20-lb. casing. Long haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Well No 5: 82- by 22-ft. derrick; oil fuel: 500 ft of 12½-in, 40-lb. casing; 1,000 ft. of 10-in, 40-lb casing; 1,575 ft. of 8¼-in, 28-lb. casing; and 1,650 ft. of 6¼-in., 20-lb. casing. Long haul of materials. Soft shales and sandstones. Drilling cost is chiefly labor.

Well No. 6: 74- by 20-ft. derrick; gas fuel; 806 ft. of 10-in casing; 1,176 ft. of 8¼-in. casing. Steam furnished from boiler plant already in operation. Short haul of materials. Soft shales and sandstones Drilling cost is chiefly labor.

Costs given for Wells 1, 2, and 3 are estimates, after J. R. Suman; those given for Wells 4, 5 and 6 are actual costs.

* Not included.

† Included with rig and derrick.

TABLE XIX.—1920 ROTARY DRILLING COSTS, ELK HILLS FIELD, CALIFORNIA, DEPTH 2,910 FT.

		Total cost	Cost per ft.
Derrick and rig	.....	$ 5,768	$ 1.98
Casing:			
2,760 ft ; 11 in. @ $3.68 per ft	$10,156		
2,700 ft., 8¼ in. @ $2.19 per ft	5,913		
210 ft., 8¼ in. @ $2.29 per ft	1,936		
Two guides	65		
Total casing	.....	$18,070	$ 6.21
Cement, 200 sacks	.....	276	.09
Tubing, 2,910 ft. @ $.44	.....	1,280	.44
Pumping equipment	.....	170	.06
Tanks, flume, etc	.....	527	.18
Total cost well equipment	.....	$20,323	
Boilers (3)	.....	$ 839	.29
Casing line, 1,200 ft	.....	250	.09
5,000 ft. O. P Rough (lumber)	.....	275	.10
Rotary and engine repair parts	.....	800	.27
Prorated charges on movable equipment	.....	$ 2,164	
Oil and distillate	.....	$ 170	
Packing	.....	180	.53
Miscellaneous materials	.....	1,200	
Materials and supplies	.....	$ 1,550	
Storehouse expense (8 per cent of store's cost)	.....	$ 1,925	.66
Hauling	.....	2,000	.69
Light and water	.....	800	.27
Tool rental	.....	1,450	.50
Cementing (Perkins)	.....	250	09
Distributed expense	.....	6,425	
Labor:			
Rotary crew, 100 days @ $118 50	.....	$11,850	4.07
Setting boilers	.....	500	.17
Setting flow tanks and flumes	.....	100	.03
Miscellaneous labor, bit dressing, etc	.....	1,250	.43
Superintendence	.....	1,850	.64
Total, labor and superintendence	.....	$15,550	
Total cost	.....	$51,780	$17.79

TABLE XX.—COST OF DRILLING WITH ROTARY RIG IN MIDWAY FIELD (3,277-FT. WELL, 10-IN. CASING), 1913

	Total cost	Cost per ft.
Derrick and rig:		
Lumber (106-ft. derrick)	$1,067.76	
Nails	28.04	
Bolts	24.80	
Corrugated galvanized iron	124.37	
Miscellaneous	2.10	
Rig irons	580.14	
Overhead expense on material	73.90	
Labor	283.06	
Shop work	145.03	
Teaming	453 98	
Total, derrick and rig		$ 2,783.18
Engines and boilers:		
Engine	$ 290 07	
Boilers (3)	1,305 00	
Foundations and settings	54.90	
Pipe and fittings	425 48	
Labor, erecting	150 00	
Belts	96.66	
Tanks and flume	196.46	
Lumber, foundation and flume framing	16 22	
Sump hole	100.00	
Total, engines and boilers		2,631.79
Drilling:		
Labor (drillers, toolies, circulator men)	$7,002.51	
Labor, extra (rigging up and pulling casing)	487 03	7,489.54
Drill tools	$ 523 96	
Drill stems and joints	3,760 00	
Depreciation on tools, machinery, stem bits, etc.	2,909 08	
Cordage	659.84	
Casing, 10-in. (2,850 ft)	5,007.86	
Casing, 6⅝-in. (3,277 ft.)	2,442 31	
Fuel (gas)	106 00	
Water	730 09	
Electricity	58.74	
Repairs (engine, rig and boilers)	476.58	
Oil, waste and packing	100.30	
Sundries: overhead material and superintendence, shop work, tools and machinery, ice, hose, miscellaneous	2,652 63	
Teaming	1,846.54	
Total, drilling		21,273 93
Fishing:		
Rental and loss of tools	$ 14 25	
Labor in fishing	245 00	
Total, fishing		259.25
Cementing (including finishing: well flowed):		
Tubing, 3,000 ft., 2½ in	$ 729 00	
Sucker rods (3,000 ft), pump, etc	266.70	
Total, cementing		995.70
Grand total		$35,436 39
Total cost per foot		$10.86
Casing cost per foot		2 28
Total labor cost per foot		2 48
Drilling labor cost per foot		2.14
Working time		125 days
Rate per day		26.2 ft.

Average Cost of Drilling Wells in the California Fields, 1914 to 1919.* The U. S. Federal Trade Commission, as the result of a survey completed in 1921,† estimates the average cost of drilling oil wells in the California fields during recent years, as follows:

* The cost of drilling 4,000-ft. wells in the Santa Fé Springs and Long Beach fields of California, during 1922 has frequently been as high as $100,000 per well.

† U. S. Federal Trade Commission, "Report on the Pacific Coast Petroleum industry," Pt. I, 1921.

TABLE XXI.—AVERAGE COST OF DRILLING, CALIFORNIA FIELDS

Year	No. of wells drilled	Average depth, ft.	Cost per foot	Cost per well	Increase in cost per well, per cent
1914	175	2,047	$10 54	$21,575	
1915	124	2,695	10 70	28 836	34
1916	389	1,941	9 83	19,080	12*
1917	465	2,066	12 22	25 246	17
1918	389	2,194	15 95	34,994	62
1919	364	2,231	19 05	42,500	97

* Decrease.

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CHAPTER VII

CASING, CASING APPLIANCES AND CASING METHODS

Purpose of Casing.—It is necessary to case wells drilled for oil for three reasons: first, to prevent the walls from caving and burying the drilling tools and well equipment; second to exclude water from the oil-producing formations; and third, to prevent waste of oil and gas, either into the atmosphere or through seepage into porous strata overlying the productive horizons. While some formations, particularly the harder sandstones and limestones, stand with vertical walls for depths of hundreds of feet and for long periods of time without casing of any sort, most of the softer rocks, such as the sands, shales and clays, cave readily. In many cases it is impossible to drill more than a few feet ahead of the casing without endangering the tools. Water is not always found in quantity in the rocks overlying the oil-producing horizons, but when it does occur it is necessary to seal it off back of a column of pipe, care being taken so to fill the space around the bottom of the pipe that water does not find its way down into the oil sands. Water entering the oil sands in quantity is found to be detrimental to continued production, and greatly lessens the ultimate recovery. In an uncased hole it is evident that gas and oil may escape from the well into porous dry strata and become dissipated through them so that complete recovery can never be effected. Furthermore, in an open hole it is impossible to prevent free escape of gas and oil into the atmosphere at the well mouth. In order to avoid these occurrences, practically all wells drilled for oil are cased with at least one column of pipe, and in many cases several telescoping strings are provided, one within the other, to make proper provision for water shut-off's, and to adapt the well lining to the necessary changes in the diameter of the bore as depth increases. The cost of casing is usually the greatest single item of expense in the cost of an oil well, and the selection of pipe weights and sizes, the planning of the casing installation, and the insertion and manipulation of the casing in the well, are among the most important problems encountered.

Requirements of Oil Well Casing.—In order to serve the purposes outlined above effectively, the casing used must be of adequate strength to resist the collapsing pressures to which it is subjected as a result of hydrostatic and earth pressure, and to resist "parting" or pulling apart under its own weight, or under extreme tension applied by pulling the pipe up when it is under considerable "friction" against the walls of the

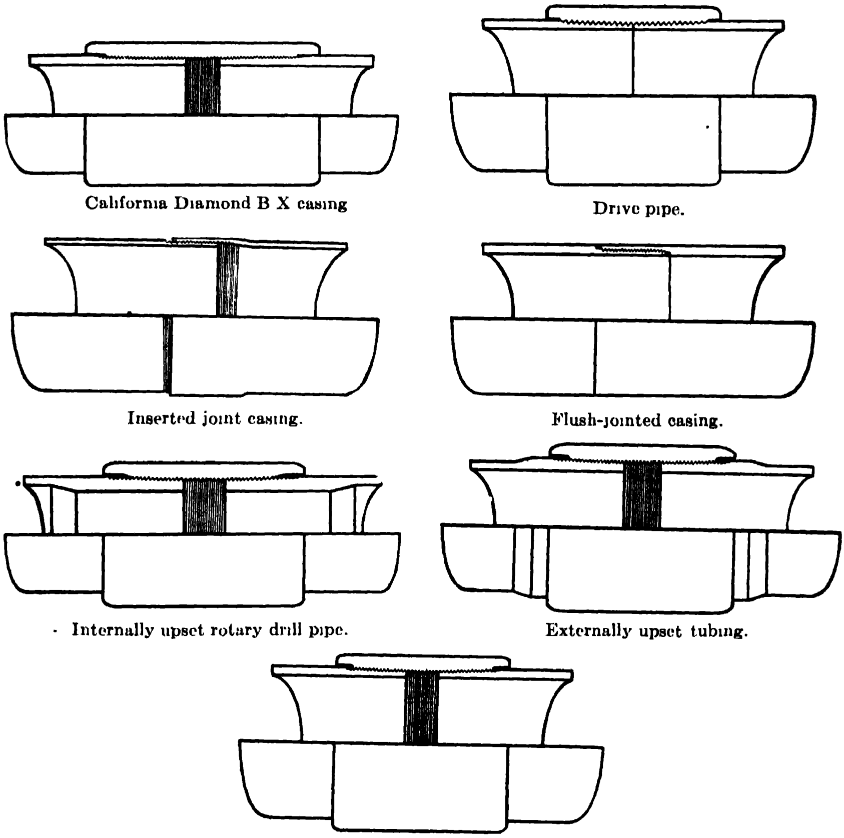
well. Frictional resistance between the casing and the walls is in large part dependent upon the design of the joints by means of which sections of pipe are connected in the well. The type of joint used must be such that in addition to adequate strength it may be readily coupled and uncoupled when desired. When in the well, the casing should present as smooth a surface as possible, both on the outside and inside—on the outside to reduce friction between the metal and the walls of the well, and on the inside to prevent the drilling tools and other casings from catching as they are lowered through. The casing must be watertight, particularly if it is to be used in sealing off water, and it should—in so far as is possible—be made of a material that resists corrosion when in contact with saline ground waters. The material must also be hard and stiff enough to resist abrasion and distortion by contact with the rock walls of the well or the drilling tools. The walls of the pipe must be as thin as is consistent with the necessary strength, in order to avoid undue loss in effective working area within the well. Since considerable amounts of casing are necessary in oil field development, it must be available at a price which will not be prohibitive.

Types of Casing.—A survey of the available materials, in view of the requirements of well casing as outlined above, indicates that wrought iron and mild, rolled steel are the only suitable materials to use. Cylindrical pipe in sections about 20 ft. long, connected with screwed joints of various types, is the form generally employed, though a pipe made of iron or steel sheets riveted together ("stove pipe") is also widely used in wells of large diameter and at shallow depths.

Screwed pipe may be had in a variety of sizes and thicknesses, and also with several different types of joints (see Fig. 100).[6] The collared joint is most used, and is generally preferred because of its greater strength, but it has the disadvantage that the collars project on the outside of the pipe, increasing the friction against the walls of the well, and reducing the effective working diameter. The inserted and flush-jointed types of screw casing are designed to overcome these difficulties, but are much weaker than the ordinary collared joint.

The cutting of a thread on the end of a pipe weakens it by reason of the metal removed in forming the thread. A section of properly made pipe is always weakest at the base of the threads, for here the metal is thinnest. With the purpose of constructing screwed-joint pipe of uniform strength throughout, some manufacturers are now making "upset-end" pipe, in which the metal is thicker at the ends by an amount equal to or greater than the depth of the threads (see Fig. 100). The additional metal is sometimes placed on the inside of the pipe (as in rotary drill pipe), but preferably on the outside if it is to be used for well tubing. Great loss of working diameter is characteristic of upset-end casings.

Methods of Manufacturing Wrought Iron and Steel Pipe.—Screwed pipe used in casing oil wells is made by a process in which sheets of metal (skelp), of proper gage and width, are rolled into cylindrical form and the edges welded to form a tube.[6] Either a lap weld or a butt weld may be used in the manufacture of steel pipe, but the former is stronger by reason of the greater width of contact at the scarfed edges, and is almost uni-



(Redrawn from illustrations in handbook published by National Tube Co.)

FIG. 100.—Types of joints used on oil well casing and tubing.

versally used in the manufacture of oil well casings. The butt weld is not used on pipe larger than 3 in. After welding, the tubes are passed through "cross-rolls" which straighten them and give them a smooth exterior surface, and are then allowed to cool slowly and uniformly in order to avoid internal strain. When cool, the rough ends are cut off and later threads are cut on each end. While not suitable for well casing, butt-welded pipe may be used for low-pressure water, gas and steam service and like purposes about the oil lease. The so-called "seamless"

tubing, made by piercing a solid round billet longitudinally and rolling out the resulting thick-walled tube on a mandrel, is too expensive for use as a well casing, but is preferred because of its superior strength, for rotary drill pipe and boiler tubes.

Properties of Material Used in Manufacture of Oil Well Casings.—The metal used in the manufacture of most oil well casings is a grade of soft or "mild" steel, made by either the Bessemer or open-hearth process. Numerous tests made under a wide variety of conditions indicate that such a steel is equal to or superior to ordinary wrought iron in its ability to resist corrosion, and it possesses a considerable advantage in greater ductility, tensile strength and durability. The manufacturers customarily subject each length of pipe to rigid tests designed to determine its suitability for the purpose intended. Oil well casings are tested to from 500 to 1,700 lb. internal hydraulic pressure, depending upon the size and weight.

Pipe Trade Customs.—The pipe is shipped from the mills in sections averaging about 20 ft. in length, with an iron or steel coupling on one end and a rough thread-protecting collar on the other. The threaded ends are "doped" or greased to protect the pipe against corrosion during transit. The rated diameter of pipe, casing and tubing up to the 15-in. size is by trade usage the *nominal* inside diameter, which, however, differs slightly from the actual inside diameter. Different grades of pipe and casing vary in thickness, but all pipe having the same nominal diameter has the same external diameter, so that they fit into the same size of coupling. For example, there are four different weights of a certain grade of casing (National California Diamond B X), weighing 40, 45, 48 and 54 lb. per foot respectively; but all are 10.75 in. in external diameter. The thickness and internal diameter, of course, vary with the weight. In ordering casing it is consequently necessary to specify the nominal diameter and the weight or thickness of wall desired. Pipes greater than 15 in. in diameter are rated by their actual outside diameter. A wide variety of "standard" sizes of casing is kept in stock by the mills and oil well supply dealers, and special sizes and weights will be made to order at slightly increased price. Permissible variations of 5 per cent above and below specified dimensions are claimed by the manufacturers.[6]

Pipe threads used on oil well casings are of the Briggs standard, 60-deg., V form (see Fig. 101). It is apparent that the thickness of metal left at the base of the threads will be greater for a shallow thread, but the tendency of the joint to pull apart by shearing or "stripping" of the threads will also be greater for a shallow thread than for a deep thread. This depends directly upon the pitch of the thread (*i.e.*, distance between threads), and maximum strength of the joint is obtained by proper balancing of these opposing factors. Oil well casings are threaded with 8, 9, 10 or 11½ threads per inch, and a cut of even 14 threads per inch is

used on some of the smaller and lighter casings. The 11½- and 14-thread cuts are so shallow that they permit the pipe to pull apart readily. Most of the casing now manufactured is cut with either 8 or 10 threads per inch, the latter number being generally preferred, though the 8-thread

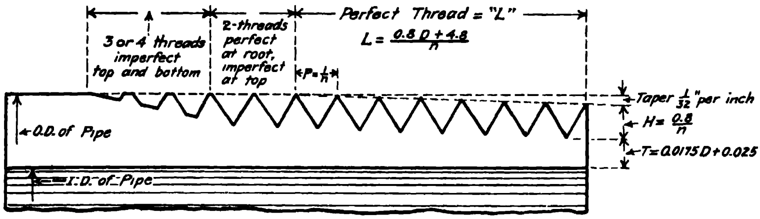


FIG. 101.—Brigg's standard pipe thread used on screw casing.

cut may be used for the heavier sizes of pipe in which the metal removed from the stock in cutting so coarse a thread will not leave the pipe too weak to sustain the heavy loads imposed. The 10-thread cut is more consistently water-tight and less liable to admit particles of sand and grit

TABLE XXII.—DEPTHS OF BRIGG'S THREADS CORRESPONDING TO VARIOUS PITCHES COMMONLY USED ON OIL WELL CASINGS

No. of Threads Per Inch	Depth of Thread in
8	100
10	080
11½	0696
12	0667
14	.0571

which destroy the thread on unscrewing. Table XXII gives the depth of threads corresponding to the different pitches used, the depth of the thread being a measure of the thickness of metal removed from the stock in cutting the thread. By subtracting these values from the thickness of the pipe, the net thickness of metal available for sustaining tensional or shearing strains may be determined. The threads are given a slight taper, varying from 3/16 to 3/4 in. of diameter per foot, measured with the axis of the pipe. This taper permits the threads to tighten securely in the collar.[6]

Casing collars are of special design, generally longer and heavier than the type of coupling used on ordinary standard pipe (see Fig. 100). To aid in starting the pipe into the coupling, a recess is turned in each end of the collar. This also serves to protect the end threads which start from the bottom of the recess at either end, tapering toward the center to conform with the taper of the pipe threads. The recessed ends of the collar fit snugly over the unthreaded casing and increase to some extent the rigidity and security of the joint. The length of the threaded portion of the collar is usually from 3 to 3½ in. The ends of the two lengths of

pipe when tightly screwed into the collar are about 1 to $1\frac{1}{2}$ in. apart, except in the case of drive pipe, in which the two ends are intended to butt together.

Types of Collared-joint Casing

A variety of casings of the collared-joint type are available on the market, differing from each other chiefly in weight or thickness, and in slight differences in the pitch of the threads and the design of the collars. There has developed a preference among drillers in different regions for particular brands of pipe which are supposedly best adapted to the conditions to be met. For example, a casing which is marketed under the name of "California Diamond B X" is widely used in the California fields. It is somewhat heavier than other grades of casing extensively used elsewhere, and is better adapted to deep-well conditions than lighter weight pipe. Table XXIII gives dimensions and weights of standard sizes of this brand of casing. For comparison, reference is also made to Table XXIV giving weights of "Standard Boston" casing, a much lighter pipe suitable for shallow-well service. South Penn casing, another well-known brand, is a pipe of intermediate weight.[6] These, or casings of the same type and of approximately equivalent weights and dimensions, should be selected for all ordinary casing installations. Special casing of additional strength may be made to order to fit particular requirements.

Drive pipe is a collared-joint type of casing, somewhat heavier than the average, that is designed particularly for use under circumstances which require heavy driving (hammering) on the upper end of the column to force it into the well. Such necessity arises in tight holes where the well is somewhat smaller than its intended diameter, or where material caves from the walls of the well about the pipe until the friction so developed prevents free movement. In order that the pipe may be driven from the surface without placing undue strain on the collars, the pitch and length of the threads are such that the ends of the joints butt together at the centers of the collars. While such a pipe is well adapted to driving, it is apt to be loosened in the collars as a result of heavy driving, and pulls apart readily when an upward pull is applied. The developments of modern methods of rotary drilling in which the casing is left fairly free of the walls of the well, have largely removed the necessity for using drive pipe; but in former years when the cable tools were used in drilling through unconsolidated formations, large quantities of it were employed. Dimensions and weights of standard sizes of a typical brand of drive pipe are given in Table XXV.

TABLE XXIII.—DIMENSIONS AND WEIGHTS OF CALIFORNIA DIAMOND B X CASING*

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
5⅝	6.000	5.352	.324	19.641	20.000	10	6.765	7⅛	15.748
6¼	6.625	6.049	.288	19.491	20.000	10	7.390	7⅝	18.559
6¼	6.625	5.921	.352	23.582	24.000	10	7.390	7⅝	18.559
6¼	6.625	5.855	.385	25.658	26.000	10	7.390	7⅝	18.559
6¼	6.625	5.791	.417	27.648	28.000	10	7.390	7⅝	18.559
6⅝	7.000	6.456	.272	19.544	20.000	10	7.698	7⅝	17.943
6⅝	7.000	6.276	.362	25.663	26.000	10	7.698	7⅝	17.943
6⅝	7.000	6.214	.393	27.731	28.000	10	7.698	7⅝	17.943
6⅝	7.000	6.154	.423	29.712	30.000	10	7.698	7⅝	17.943
7⅝	8.000	7.386	.307	25.223	26.000	10	8.888	8⅛	27.410
8¼	8.625	8.017	.304	27.016	28.000	10	9.627	8⅛	33.096
8¼	8.625	7.921	.352	31.101	32.000	10	9.627	8⅛	33.096
8¼	8.625	7.825	.400	35.137	36.000	10	9.627	8⅛	33.096
8¼	8.625	7.775	.425	37.220	38.000	10	9.627	8⅛	33.096
8¼	8.625	7.651	.487	42.327	43.000	10	9.627	8⅛	33.096
9⅝	10.000	9.384	.308	31.881	33.000	10	11.002	8⅛	38.162
10	10.750	10.054	.348	38.661	40.000	10	11.866	8⅛	45.365
10	10.750	9.960	.395	43.684	45.000	10	11.866	8⅛	45.365
10	10.750	9.902	.424	46.760	48.000	10	11.866	8⅛	45.365
10	10.750	9.784	.483	52.962	54.000	10	11.866	8⅛	45.365
11⅝	12.000	11.384	.308	38.460	40.000	10	13.116	8⅛	50.445
12½	13.000	12.438	.281	38.171	40.000	10	14.116	8⅛	54.508
12½	13.000	12.360	.320	43.335	45.000	10	14.116	8⅛	54.508
12½	13.000	12.282	.359	48.467	50.000	10	14.116	8⅛	54.508
13½	14.000	13.344	.328	47.894	50.000	10	15.151	9⅛	67.912
15½	16.000	15.198	.401	66.806	70.000	10	17.477	9⅛	98.140
				Additional Sizes					
4½	4.750	4.082	.334	15.752	16.000	10	5.364	6⅝	9.963
4¾	5.000	4.500	.250	12.682	12.850	10	5.491	6⅝	8.533
4¾	5.000	4.408	.296	14.870	15.000	10	5.491	6⅝	8.533
6⅝	7.000	6.336	.332	23.643	24.000	10	7.698	7⅝	17.943
11	11.750	11.000	.375	45.557	47.000*	10	12.866	8⅛	49.379
11	11.750	10.772	.489	58.811	60.000	10	12.866	8⅛	49.379
12½	13.000	12.220	.390	52.523	54.000	10	14.116	8⅛	54.508

* As manufactured by National Tube Co. All dimensions are expressed in inches, weights in pounds.

TABLE XXIV.—DIMENSIONS AND WEIGHTS OF "STANDARD BOSTON" CASING*

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
2	2 250	2 050	.100	2.296	2 340	14	2 714	2⅝	1.361
2¼	2 500	2 284	.108	2 759	2 820	14	2 964	2⅝	1.499
2½	2 750	2 524	113	3 182	3 250	14	3 214	2⅞	1.804
2¾	3 000	2.768	116	3 572	3 650	14	3 464	2⅞	1 957
3	3 250	3 010	120	4 011	4.100	14	3 771	3⅛	2 612
3¼	3 500	3 250	.125	4 505	4.600	14	4 021	3⅛	2.799
3½	3 750	3.492	129	4 988	5 100	14	4 271	3⅛	2 987
3¾	4 000	3 732	.134	5.532	5 650	14	4.521	3⅛	3.174
4	4.250	3 974	138	6 060	6 200	14	4.771	3⅝	3 923
4¼	4 500	4 216	.142	6.609	6 750	14	5 021	3⅝	4 141
4¼	4.500	4 090	205	9 403	9.500	14	5 021	3⅝	4.141
4½	4 750	4 460	145	7 131	7 250	14	5 271	3⅝	4 360
4½	4 750	4 364	.193	9 393	9 500	14	5 271	3⅝	4.360
4¾	5 000	4 696	152	7.870	8 000	14	5 521	3⅝	4.578
5	5 250	4.944	153	8 328	8 500	14	5 828	4⅛	5.929
5	5 250	4 886	182	9 851	10 000	14	5 828	4⅛	5 929
5	5 250	4 886	182	9 851	10 000	11½	5 800	4⅛	5 742
5	5 250	4.768	.241	12 892	13 000	11½	5 800	4⅛	5 742
5	5 250	4 648	.301	15 909	16 000	11½	5 800	4⅛	5 742
5 3/16	5 500	5 192	154	8 792	9 000	14	6 078	4⅛	6 200
5⅝	6 000	5 672	164	10 222	10 500	14	6 664	4⅛	7 729
5⅝	6 000	5.620	190	11 789	12 000	11½	6 636	4⅛	7 516
5⅝	6 000	5 552	224	13 818	14 000	11½	6 636	4⅛	7 516
5⅝	6 000	5 450	275	16 814	17.000	11½	6 636	4⅛	7 516
6¼	6 625	6 287	169	11 652	12 000	14	7 308	4⅝	9.825
6¼	6 625	6 255	.185	12 724	13 000	14	7.308	4⅝	9.825
6⅝	7 000	6 652	.174	12 685	13 000	14	7 692	4⅝	10 497
6⅝	7 000	6 538	231	16.699	17 000	11½	7 664	4⅝	10.225
7¼	7 625	7.263	181	14 390	14 750	14	8 317	4⅝	11 401
7⅝	8 000	7 628	.186	15 522	16 000	11½	8 788	5⅛	15 308
7⅝	8 000	7 528	236	19 569	20 000	11½	8 788	5⅛	15 308
8¼	8 625	8 249	188	16 940	17 500	11½	9 413	5⅛	16 461
8¼	8.625	8.191	.217	19 486	20 000	11½	9 413	5⅛	16 461
8¼	8 625	8 097	.264	23 574	24 000	11½	9 413	5⅛	16.461
8⅝	9 000	8.608	.196	18.429	19 000	11½	9 788	5⅛	17.153
9⅝	10.000	9.582	.209	21 855	22 750	11½	10 911	6⅛	26.136
10⅝	11.000	10.552	224	25.780	26 750	11½	11 911	6⅛	28.536
11⅝	12.000	11 514	243	30 512	31 500	11½	12 911	6⅛	31 051
12½	13.000	12.482	.259	35 243	36 500	11½	14 025	6⅛	37.499
13½	14 000	13 448	276	40 454	42 000	11½	15.139	6⅛	44 495
14½	15 000	14 418	.291	45.714	47 500	11½	16.263	6⅛	52.401
15½	16 000	15.396	.302	50 632	52 500	11½	17 263	6⅛	55.779

* As manufactured by National Tube Co. All dimensions are expressed in inches weights in pounds.

TABLE XXV.—DIMENSIONS AND WEIGHTS OF DRIVE PIPE*

Size	Diameters		Thickness	Weight per foot		Threads per inch	Couplings		
	External	Internal		Plain ends	Threads and couplings		Diameter	Length	Weight
2	2.375	2.067	.154	3.652	3 730	11½	2.923	3⅝	2.380
2½	2.875	2.469	203	5.793	5.906	8	3 486	4⅛	3.748
3	3.500	3 068	216	7 575	7 705	8	4.111	4⅛	4.493
3½	4 000	3 548	226	9 109	9.294	8	4.723	4⅛	5 973
4	4.500	4 026	237	10 790	10.995	8	5.223	4⅛	6.740
4½	5.000	4 506	.247	12.538	12.758	8	5.723	4⅛	7.439
5	5.563	5 047	.258	14.617	14.989	8	6 410	5⅛	11.871
6	6.625	6 065	280	18.974	19.408	8	7 473	5⅛	13.956
7	7.625	7 023	.301	23 544	24 021	8	8 474	5⅛	15.955
8	8 625	8 071	277	24 696	25 495	8	9 588	6⅛	24.343
8	8 625	7 981	322	28 554	29 303	8	9.588	6⅛	24.343
8	8 625	7.917	354	31 270	32.334	8	9 882	6⅛	31.320
9	9.625	8.941	342	33 907	34.711	8	10.588	6⅛	27.035
10	10 750	10 192	279	31 201	32 631	8	11.950	6⅝	40 108
10	10.750	10 136	.307	34 240	35.628	8	11 950	6⅝	40.108
10	10 750	10 020	365	40 483	41 785	8	11 950	6⅝	40 108
11	11 750	11.000	375	45 557	46 953	8	12 950	6⅝	43 664
12	12 750	12.090	330	43 773	45 358	8	13.950	6⅝	47.220
12	12.750	12.000	.375	49.562	51 067	8	13.950	6⅝	47.220
13	14.000	13 250	.375	54.568	56 849	8	15.438	7⅛	66.024
14	15.000	14 250	375	58 573	61.005	8	16.438	7⅛	70.533
15	16.000	15.250	375	62 579	65 161	8	17.438	7⅛	75.043
17O.D.	17.000	16 214	.393	69 704	73 000	8	18.675	7⅛	91.746
18O.D.	18 000	17.182	409	76 840	81.000	8	19.913	7⅛	109.669
20O.D.	20 000	19.182	.409	85 577	90.000	8	21 913	7⅛	121.298

* As manufactured by National Tube Co. All dimensions are expressed in inches, weights in pounds.

Upset-end Pipe.—The advantages of upset-end pipe, in which the metal is reinforced where the threads are cut, so that it is of uniform strength throughout, have already been suggested. Such pipe is used chiefly as rotary drill pipe, and in small sizes as oil well tubing, though to a limited extent also as casing. Weights and sizes of upset-end oil well tubing are given in Table XXVI.

TABLE XXVI.—DIMENSIONS AND WEIGHTS OF UPSET-END OIL WELL TUBING*

Size	Diameters		Thickness	Weight per foot		Threads per inch	O. D. of upset	Couplings		
	External	Internal		Plain ends	Threads and couplings			Diameter	Length	Weight
2	2 375	2 067	.154	3 652	3.731	11½	2 9/16	3.057	3⅝	2.484
2½	2.875	2 469	.203	5 793	5.903	8	3 1/16	3 616	4⅛	3.845
3	3.500	3 068	.216	7 575	7.699	8	3 11/16	4 237	4⅛	4.557
3½	4.000	3.548	.226	9.109	9.287	8	4 3/16	4.848	4⅛	6.036
4	4.500	4.026	.237	10 790	10 984	8	4 11/16	5 345	4⅛	6 768
4½	5.000	4.506	247	12 538	12.744	8	5 3/16	5 842	4⅛	7.426
5	5.563	5 047	258	14.617	14 962	8	5¾	6.509	5⅛	11.821
6	6.625	6 065	280	18.974	19 359	8	6⅞	7.627	5⅛	13.931
7	7.625	7 023	.301	23.544	23 957	8	7⅞	8 621	5⅛	15.778
8	8.625	7.981	.322	28 554	29.196	8	8⅞	9.729	6⅛	24.119

* Externally upset, as manufactured by the National Tube Co. All dimensions are expressed in inches, weights in pounds.

Inserted-joint Casing.—When a well is shallow and a light casing is all that is needed to sustain the walls, inserted-joint casing may be advantageously employed. This type of joint is often used for liners, and is also preferred in cases where it is necessary to economize in working space within a well of small diameter. In this type of casing one end of the tube is expanded and internally threaded, so that the end of one joint receives the externally threaded and unexpanded end of another joint (see Fig. 100). The threads are only slightly tapered. Modified forms have also been developed in which the outer half of the joint is expanded and the inner half is "cressed." In another variety, a faced ring is screwed on the externally threaded end, against which the outside or expanded half of the joint butts when the parts are screwed together. This prevents the expanded end from splitting and adds to the security of the joint to such an extent that it can be lightly driven if necessary.

Flush-jointed casing is made by turning down and cutting a thread on one end of a tube, and boring out and threading internally the end of another tube (see Fig. 100). The end of one tube thus screws into the other, without the necessity for a collar, and the joint has no visible edges or corners on either the outside or inside of the pipe. Such a joint is particularly useful where the diameter of a well has become so reduced that it is important to use a casing that occupies the smallest possible space. It is useful also, because of its smooth exterior surface, in casing

off loose sands which tend to cave and pack around the couplings of ordinary pipe. The joint is inherently weak, however, due to the necessity of cutting away half of the metal on each tube at the joint. The threads must be fine and tend to pull apart readily. Flush-jointed casing is screwed together until the ends of the tubes butt together at the center of the joint. In this condition it is watertight, though not recommended for water exclusion, and can be lightly driven; but any deflection from the vertical will generally result in fracture at the base of the threads. It is rarely used in oil field operations.

Welding Joints in Oil Well Casing Installations.—The success attained in welding line pipe for the transmission of oil and gas has led to the welding of oil well casings as a substitute for the screw joint.[4] It is perfectly feasible to weld wrought iron or steel pipe in the derrick with the aid of the oxyacetylene torch, and the resulting joint is as strong as is possible with any form of screw joint if the welding is properly done. Plain-end pipe (without threads) is used, with ends beveled on the outside, the joints being butt-welded above the derrick floor as they enter the well (see page 229). Joining pipe in this way, however, is slower than when threaded collars are used, and it is impossible to remove a string of welded casing from the well without cutting the sections apart. The fire risk involved in using a torch about the mouth of a well which may be producing inflammable oil or gas must also be considered.

The cost of a welded string of casing is about the same as that of ordinary collared-joint casing, the saving in cost of threading and collars being approximately offset by the cost of preparing the joints and welding them together. The method is used particularly in welding "liners," the column of casing which penetrates the oil-producing zone; but it has also been successfully used in welding larger pipes, particularly in redrilling jobs where it has been necessary to "sidetrack" an old column of casing, a condition which might lead to interlocking of collars on the two strings. In fields where the producing formation is a loose sand, the material tends to pack about the collars of ordinary casing, making removal of the liner difficult, particularly if the hole is crooked. Much of this trouble is overcome by the use of a welded liner. In some California wells, welded strings of 8¼- and 10-in. casings 1,100 ft. in length have been successfully inserted. Some operators make a practice of "spot welding" the collars on ordinary casing to prevent the joint from loosening in the well.

Riveted casing (stove pipe) is made of thin sheets of wrought iron or steel rolled into cylindrical form and riveted at the seams (see Fig. 102). The individual joints are 2 or 3 ft. long and are usually made of two sheets of metal, one cylinder within another, and so placed with respect to each other that the end of one cylinder is just opposite the

center of the other. This results in the inside cylinder projecting for half its length at one end, leaving a corresponding recess within the outer cylinder at the opposite end. When such joints are put together, the projecting inside sheet of one joint is forced into the center of the outside sheet of another, until the inside sheets of the two joints butt together. The result is a continuous, double-walled cylinder. Con-

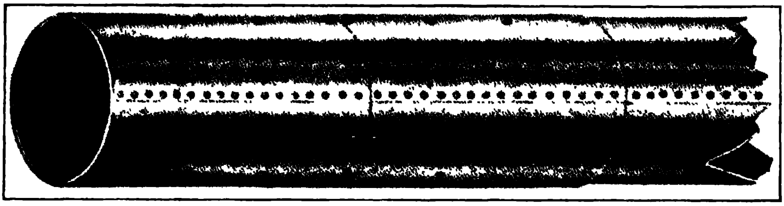


FIG. 102.—Riveted casing or "stove pipe."

siderable friction develops between joints when they are forced together, and it is customary to increase this by denting the outer cylinder against the inner with the point of a sharp pick. The frictional contact between joints, thus developed, is usually all that is provided to hold them together. Occasionally, however, when a long column of stove pipe is to be placed in a well and there is danger of the column pulling apart under its own weight, the joints will be riveted together. This is accomplished by lowering a close-fitting mandrel inside the pipe to serve as an anvil, and driving the rivets against the mandrel through holes previously drilled and countersunk on the inside.[7]

Riveted casing is generally used in wells of large diameter, say 12 in or greater, though it may be had in sizes as small as 4 in. Sizes up to and including 20 in. are regularly carried by the manufacturers, and larger sizes may be made to order for wells of exceptional diameter. In the Russian fields where this kind of casing is used almost exclusively, casings as large as 36 in. in diameter are not uncommon. The metal sheets used in forming stove pipe vary from 1/8 to 5/16 in. in thickness, the sheets being cut to proper size and all rivet holes punched and countersunk before the cylinders are rolled. The pipe, ready for insertion into the well, may be had from the manufacturers or supply dealers in either single joints, or in sections ranging in length from 10 to 21 ft., the individual joints making up each section being riveted together at the joints as well as along the seams. Riveted casing is not ordinarily watertight, though it can be made approximately so by careful caulking of all seams and joints. However, it is not ordinarily heavy enough to withstand any great hydrostatic head that may build up behind the casing in wet formations.

It is customary to reinforce the first joint (or "starter joint") of a column of stove pipe, either by riveting on a steel shoe, or by construct-

ing the first joint of 3 or 4 sheets of metal instead of 2. The latter type of reinforcement is generally preferred because of the smaller clearance necessary. Such reinforcement assists in preventing abrasion and distortion of the lower end of the pipe by contact with the walls of the well.

Riveted casing is only intended for light service and is seldom used at greater depths than 800 ft. because of its tendency to pull apart under its own weight. However, single columns of 16-in. stove pipe over 1,000 ft. long have been successfully placed in wells under favorable conditions. For the same reason, when once started into the well, it cannot usually be raised if there is friction against the walls. It can only be driven lightly since the joints have a tendency to telescope and buckle; or if the lower end of a column is hanging freely in the well, it may be jarred off by the resulting vibration. It is easily deformed by pressure from the walls, or in passing through a flat hole. The chief advantages of riveted casing are its smooth exterior surface, small space occupied in the well, and lower cost. Because of its smooth outer surface, it is particularly adapted to casing off loose, sandy surface strata which tend to cave and bind against the couplings on collared-joint casing. Loss in effective working diameter within the well is reduced to a minimum through the use of this class of casing.

CASING APPLIANCES

The installation and manipulation of casing in the well and within the derrick requires the use of a variety of special appliances worthy of brief description. These include casing elevators, hoisting blocks, casing hooks and spiders for lifting, lowering and suspending a column of pipe; casing shoes attached to the lower end of a column of pipe to aid it in cutting its way through projections on the walls of the well, and to reinforce the lower end of the column against damage thereby; casing tongs for screwing sections of pipe together; drive heads and clamps used in driving casing into a tight hole; and casing jacks useful in applying a powerful lifting force to casing that has become partially "frozen" by friction against the walls of the well. In addition to these, there are numerous other devices, some of which are described below, while others pertaining particularly to fishing operations are reserved for a later chapter.

Casing Shoes.—It is customary to place on the outside of the bottom of every column of casing lowered into the well, a reinforcing shoe of steel, specially formed to prevent distortion and abrasion of the pipe, and to aid it in cutting a way for itself past minor obstructions on the walls. The lower edge is beveled to a blunt cutting edge on the outer circumference. Casing shoes are somewhat larger in outer diameter than the collars on the casing to which they are attached, in order to insure free passage of the pipe for any opening through which the shoe has passed.

They are usually about 1 in. thick, from 10 to 16 in. long and weigh in the case of the larger sizes from 100 to 200 lb. There are several patterns (see Fig. 103) some of which are designed to screw on the bottom joint of casing, while others are shrunk on. The Texas pattern is both screwed and riveted to the casing. The Baker shoe has a series of square teeth cut on its lower end. By rotating a casing equipped with this shoe, the casing itself is capable of cutting a way for itself past minor obstruc-

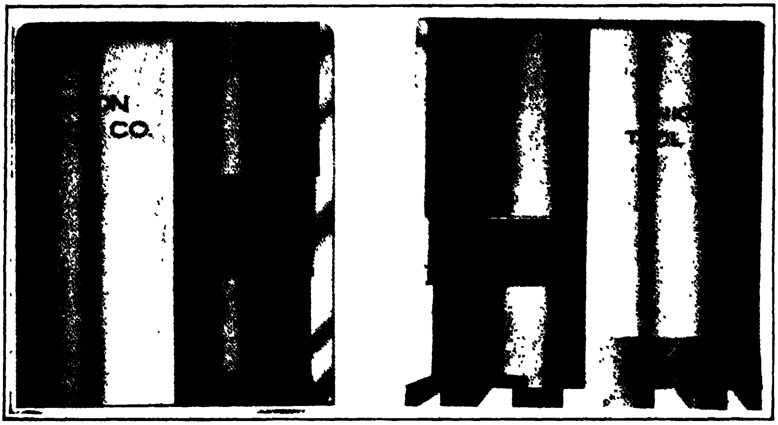


FIG. 103.—Types of casing shoes.
Left, common form; right, Baker shoe.

tions. When pipe is to be worked down through hard rock, such a shoe offers a considerable advantage. The material used in the manufacture of casing shoes is preferably a good grade of hardened plow steel. Casing shoes designed to screw on the casing usually have a narrow recess turned in the upper end above the threads, and a shoulder below the threads. The casing screws into the shoe until it butts against the shoulder, and the annular space above the threads formed by the recess, between the casing and the shoe is filled with molten lead or babbitt metal. This strengthens the screw joint and prevents the shoe from becoming detached in the well. The shoe provided must be especially heavy when it is expected that driving of the pipe will be necessary.

For use in the unconsolidated formations of the California fields, some operators construct unusually heavy and long casing shoes by shrinking short sections of heavy tubular steel on a joint of casing and dressing the outer surface to a slight taper with a blunt cutting edge at the lower end.

Casing Elevators.—In lifting or lowering a joint or column of casing suspended vertically, it is necessary to provide some sort of a clamp which will grip the pipe securely, to which the necessary hoisting tackle may be attached. The device usually employed for this purpose is called a casing

elevator, and is so designed that it may be clamped loosely around the pipe below the top collar, the weight of the pipe falling on the lower edge of the collar.

The elevator finds constant use when casing is being inserted into a well, each new joint being lifted from the derrick floor and suspended on the elevator until it is screwed into the collar of the preceding joint, after which the entire column is lowered while suspended on the elevator. Such service requires an elevator that can be rapidly clamped and unclamped, and which suspends the casing vertically so that it can be freely

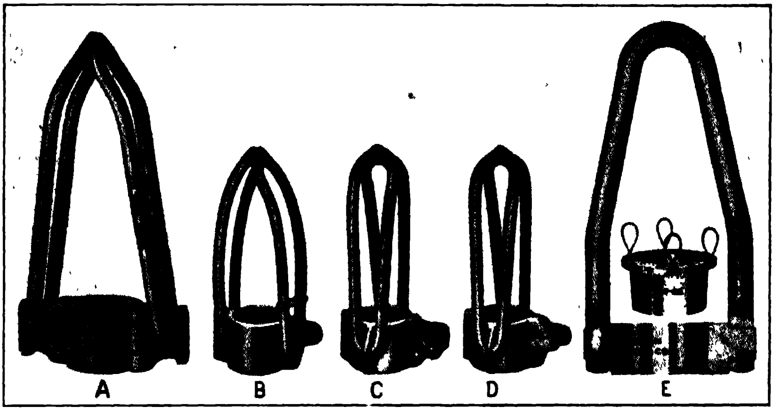


FIG. 104.—Types of elevators.
A, Ideal, *B*, Mannington; *C*, Fair-Mannington; *D*, Fair and *E*, single link.

rotated while being screwed into the collar below. It must be of adequate strength to support the weight of the entire column of casing, which may in a long column of large diameter pipe aggregate as much as 50 tons. It is imperative, under the conditions pertaining, that the elevator be so designed that it offers adequate security against accidental opening of the clamps and dropping of the casing while under strain.

A variety of different patterns of elevators have been designed and are available on the market, differing from each other chiefly in the manner of latching in the locked position. The Fair, Scott, Mannington, Ideal and Wilson patterns are well known and commonly used types. These are illustrated in Fig. 104. It will be noted that in each case there is a pair of semi-circular clamps hinged at one side and provided with a locking device of some sort at the other. There is also a pair of heavy links, suitably curved to bring the point of support over the center of the pipe, passing through holes in heavy lugs attached to the side of the clamps. The inside diameter of the clamps is slightly greater than the outside diameter of the pipe for which it is intended. One type of elevator has a single link instead of two. The body of the elevator is in this case in one piece and has an opening through it which permits of its passing freely

over the casing collar. With the elevator just below the top collar, a split bushing of proper size is slipped into the elevator and around the pipe, furnishing the means of applying a lifting force under the collar. Casing elevators are made of wrought iron or steel and are necessarily of heavy construction, ranging in weight from 200 to upwards of 2,500 lb. in the larger sizes of the heavier models. In addition to their use in handling casing, they find application in coupling and uncoupling rotary drill pipe (see page 168) and oil well tubing (see page 366).

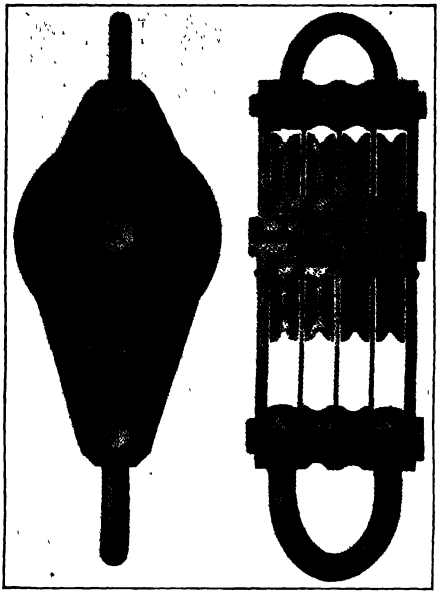
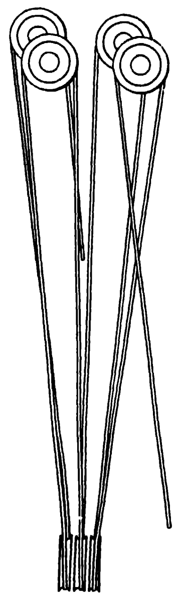


FIG. 105.—Four-sheave roller-bearing traveling block.



(*After T. Curtin in U. S. B. Mines Bull. 182*).

FIG. 106.—Illustrating manner of stringing three-sheave traveling block.

Casing Blocks or Hoisting Blocks.—The mechanical advantage necessary in handling a long string of heavy casing is secured through the use of a hoisting block containing from one to four sheaves, the calf or casing line being threaded between these and two or more sheaves at the derrick crown. The sheaves range in diameter from 10 to 26 in., and are supported by a heavy metal frame from 18 to 48 in. long, consisting of plates separating the sheaves and spaced apart by cylindrical spools, and held together by three bolts, one of which, equipped with a loose bushing, serves as a shaft for the sheaves to turn on (see Fig. 105). A bail or link at both top and bottom provides a means of attaching ropes or hooks. Casing blocks should have a low center of gravity so that they do not "turn over" when the load is applied.

The mechanical advantage secured will depend upon the number of lines used and the method of stringing.[3] The power applied at the calf wheel drum will be multiplied as many times as there are lines strung between the hoisting block and the derrick crown, and the hoisting speed will be correspondingly diminished. Usually the end of the casing line or dead line will be attached to the top bail of the casing block, though in the case of the combination rig, the other end may be attached to the draw works hoisting drum. Fig. 106 illustrates the usual manner of stringing a casing block having three sheaves for the use of 7 lines. If only five lines are desired, one of the pulleys may be left unstrung. One end of the cable is the dead line. The other end, coiled on the calf wheel shaft or hoisting drum should be carried to the far side of the nearest pulley as shown in the illustration, otherwise the blocks will not be in alignment with the hole and starting the casing into the collars at the well mouth is made difficult. This causes loss of time in handling casing, and may result in a joint of pipe being cross-threaded in the collar, a condition which permits the joint to pull apart when strain is applied.

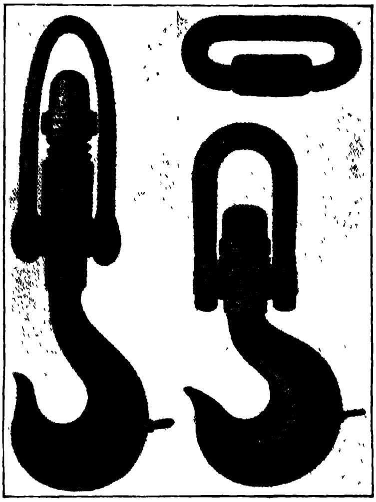


FIG. 107.—Types of casing hooks and link.
Left, "wigle spring" hook; lower right, conebearing hook, upper right, strapped C-link

Casing Hooks and Links.—The elevators are suspended from the lower bail of the hoisting block by a massive hook and a heavy split link or C-hook (see Fig. 107). The larger sizes of casing hooks weigh as much as 500 lb. The hook must be free to turn in its supporting trunnion so that the casing can be rotated while suspended on the elevators, without twisting the lines above the hoisting block. The bearing between the hook stem and the trunnion is often equipped with cone or ball bearings to eliminate friction, and in one type a spring is inserted to avoid the destructive jerk that otherwise results from sudden application of the power in lifting a column of casing. A clevis is sometimes attached to the edge of the hook for connecting a small control rope.

Casing Spiders or Wedge Blocks.—In handling casing in the well, a means must be provided for suspending a column of casing from the surface in such a manner that the open end of the casing is left free for drilling, bailing or other operations. For this purpose, a casing spider is used. This consists of a heavy forged steel ring with a conical hole through its center (*i.e.*, larger at the top than at the bottom), and two

projecting lugs at opposite points on the circumference (see Fig. 108). The hole through the ring is large enough to admit the largest sizes of casing, and conical steel liners are provided to adapt it to use with smaller sizes of pipe. Curved steel wedges, called "slips"—usually four in number —fit into the conical opening of the spider or liner, in such a manner that when in position they form a cylindrical opening just large enough to

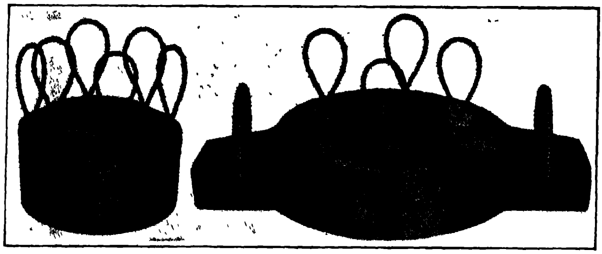


FIG. 108.—Casing spider with bushing and extra liner and slips.

admit the pipe. The inner edges of the slips are machined with horizontal serrated grooves. With the pipe suspended through the spider, the slips are dropped into position, and as the pipe is slowly lowered, the slips slide down on their conical supports and are thus forced in against the pipe until the latter is gripped securely. The greater the weight of the column of casing, the more securely it is held. To remove the casing from the spider, it is only necessary to lift the casing slightly and withdraw the slips. Wire rope loops are provided on the ends of the slips so that they may be readily placed in position or withdrawn without danger to the operator. The spider may rest either on the derrick floor or on timber supports in the bottom of the cellar; or it may be supported on cables or rods passing through links attached to the lugs. The weight of a casing spider ranges from 475 to nearly 2,000 lb., depending upon the maximum size of pipe for which it is designed.

Casing Tongs.—For turning the pipe in coupling and uncoupling screwed joints, pipe tongs of special design are provided. There are two general types: (1) the hinged-jaw type, and (2) chain tongs. The former are generally preferred for heavy service because of their positive grip, quick release and ease of application. A number of representative forms are illustrated in Fig. 109. Because of the heavy duty imposed upon them, casing tongs are necessarily large and heavy, the larger sizes weighing as much as 450 lb. Because of their great weight, it is necessary to suspend them in a horizontal position from a derrick crane or from a balanced beam in the derrick. The jaws of casing tongs are often equipped with bushings which adapt the same tongs to various sizes of pipe. Some models are reversible so that the pipe may be either screwed or unscrewed from one position of the tongs, that is, without

turning the tongs over. This is accomplished by merely changing a metal pin controlling the leverage from one hole to another in the jaws.

A power-driven machine for screwing and unscrewing casing in the derrick, known as the Brandon Power Casing Machine, has been designed, but up to the time of writing has been used only in an experimental way. It consists of a geared table surrounding the pipe and supported above the derrick floor. On this table a carriage, which grips the joint of pipe

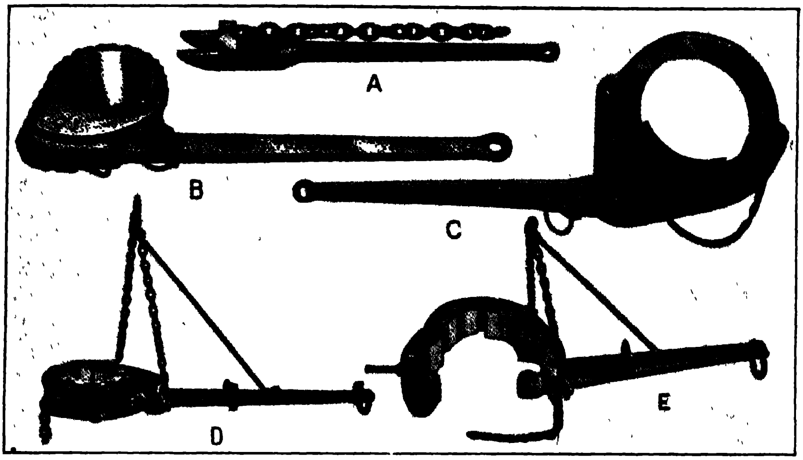


FIG. 109.—Types of casing tongs.

A, Kellerman chain tongs, *B*, Hardison tongs, *C*, Maddren tongs; *D*, Griffin tongs closed and *E*, open.

above the collar, revolves. The power is transmitted through the gearing provided from a small vertical engine. It is claimed by the manufacturers that this machine operates more steadily and evenly than is possible with hand tongs, with less strain on the casing threads and with much greater speed.

Casing Wagons.—Before it is placed in the well, casing is usually stacked on the casing rack at one side of the derrick, and as it is needed, it must be brought into the derrick and turned on end with the aid of the elevators. To aid in supporting and transporting the casing while it is in the horizontal position, two-wheeled casing wagons are provided, one to be placed at each end of the joint of pipe. One of these is equipped with a V-shaped support in which the front end of the pipe rests, and the other has a projecting hook which enters the rear end, and by depressing the handle, lifts the pipe from the floor. The wheels and carriages are made entirely of steel, with pipe handles. Wooden or steel "dollies" consisting of a solid roller mounted under a small supporting carriage are preferred by some drillers in transporting casing and drill stem from the casing rack into the derrick.

Casing Adapters, Shoe Guides and Floating Plugs.—When a string of casing in a well does not extend to the surface and a smaller string of pipe or tools must be lowered through it, there is danger of the tools or smaller casings "hanging up" on the upper end of the column. To avoid this, it is customary to place a casing adapter on the top of the column of

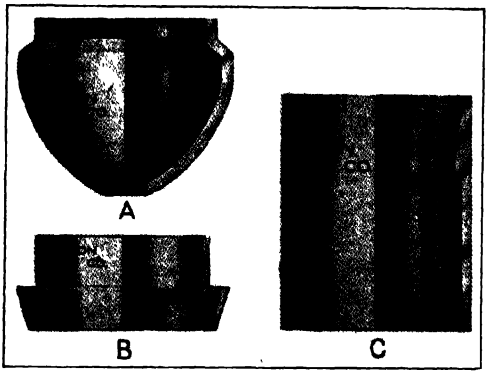


FIG. 110.—Floating plug (*A*), shoe guide (*B*) and casing adapter (*C*).

pipe in the well, which is beveled to guide the smaller string or tool through the opening (see Fig. 110). Instead of this, or in addition to this, the shoe on the smaller string of pipe may be equipped with a shoe guide which serves the same purpose.

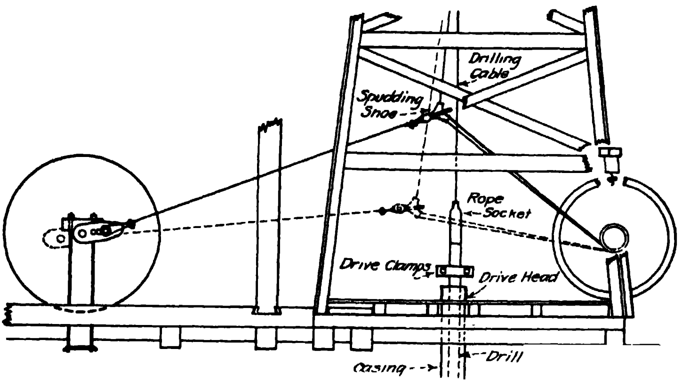


FIG. 111.—Illustrating method of driving casing.

In lowering a long string of casing into a well filled with water or mud, considerable strain may be taken off the elevators, spider and hoisting block if the lower end of the column be closed with a floating plug. In fact, if water be excluded from the casing, the buoyant force exerted is sufficient to float the column except in the case of the heaviest grades of pipe. Often, however, the well will not be full of fluid and the floating

plug takes care of only a part of the total weight. The plug used is generally hemispherical in form and is screwed to the bottom of the casing shoe (see Fig. 110). Being made of cast iron, it is readily broken up with the drilling tools when the casing has been "landed."

Drive Clamps and Heads.—When it becomes necessary to drive casing into a well, the cable drilling tools are generally used to provide the necessary impact. The tools are lowered into the well until the wrench square on the top of the drill stem is slightly above the top of the casing column. A pair of heavy clamps, with a square opening through them and held together by two bolts, are then clamped securely to the

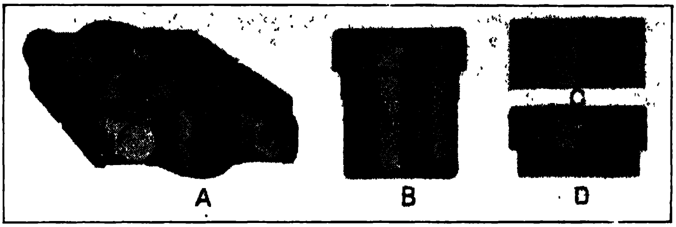


FIG. 112.—Drive clamps and heads.
A, clamps, *B*, drop head, *C* and *D*, screw heads

wrench square; the bull wheel brake is clamped, a spudding shoe is placed on the drilling cable, and a jerk line is connected from the spudding shoe to the wristpin on the crank (see Fig. 111). The clamps placed on the stem are of such size that they do not pass through the open end of the casing. With the tools operated as in spudding (see page 125), the full weight of the string of tools is allowed to fall on the top of the column of casing with each stroke, the drive clamps striking on a "drive head," which has been previously screwed into the top coupling or on the top of the column of casing. Some types of drive heads are without threads and merely rest on the top of the column of casing. Typical drive clamps and heads are illustrated in Fig. 112.

Casing Jacks.—In freeing partially frozen casing, or in pulling casing from a well about to be abandoned, a powerful lifting force is often necessary. The force of the engine, even as multiplied by the calf wheel and hoisting block, is often inadequate, and recourse is had to the use of casing jacks. These are of two types: (1) screw jacks, and (2) hydraulic jacks. With the principle of the screw and the hydraulic jack it is assumed the reader is familiar. The latter are the more powerful, some of those designed for oil well service being capable of lifting a load of 250 tons. In either case the jacks are applied through the aid of a casing spider which grips the pipe, two jacks being used, one under each lug on either side of the spider (see Fig. 113).

In placing stove pipe in a well, instead of driving it, it is sometimes preferable to use the pressure of a casing jack in forcing the casing down. For this purpose, a stove pipe "push head" is placed on the top of the column and the jack applied, rigged to push against anchor clamps bolted securely to the derrick foundations.

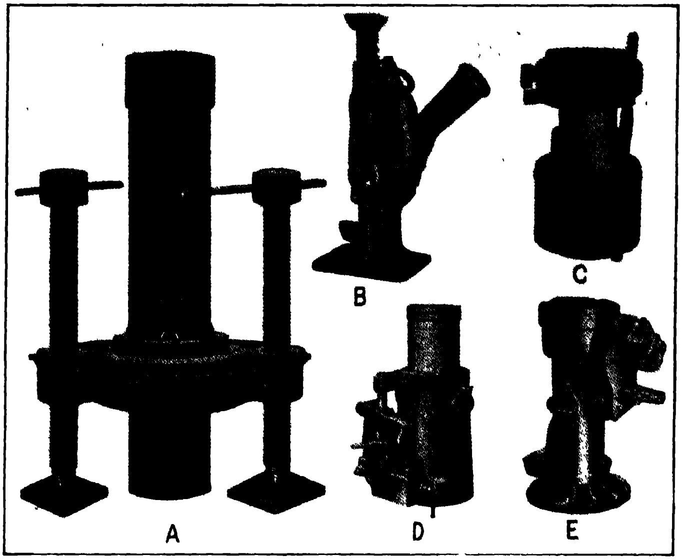


FIG. 113.—Types of jacks.
A, screw jacks lifting casing, *B*, lever type of jack, *C*, *D* and *E*, types of hydraulic jacks.

Casing Testers.—When a string of pipe has been used to exclude water from a well, it is sometimes necessary to find the position of a leak which may be admitting water. For this purpose, a swab casing tester is used. This consists of a small cylindrical receptacle closed at the lower end, and with a leather disc of such a diameter as will fit snugly inside of the casing fastened around the top. A small bail permits of supporting the device on the sand line. Lowered to successively greater depths, occasionally withdrawing it to the surface to note whether or not water has accumulated in the tube, the leak is soon located and the necessary steps taken for its repair (see Fig. 156).

CASING INSTALLATIONS

Design of a Casing Installation.—The selection of sizes and weights of pipe to be used in casing a well, determination of the position of water shut-offs and the depth to which each string of pipe will be carried, should in so far as is possible be worked out in advance of actual drilling operations. If the well is a wild-cat well and the depth of the producing

horizon and character of the formations to be penetrated are uncertain, it will be impossible to plan the casing installation definitely in advance, that is, changes in size of casing, determination of the position of water shut-offs, etc., must be made from time to time as the work proceeds. But in a partially developed territory where the conditions to be met are approximately known, it should be possible, barring accidents, to select definitely all of the casing in advance and carry out its installation according to prearranged schedule.

In the latter case, the operator must first determine how many strings of pipe or how many changes in diameter will be necessary to reach the desired depth. This depends upon the depth of the producing horizon, the nature of the formations to be penetrated and the number of water shut-offs necessary. Each water shut-off requires a change in the size of casing. The method of drilling used and the depth to which it is possible to carry a string of pipe in the given territory must also be taken into account. With the rotary equipment much greater freedom in selection of lengths of individual strings is possible than when the cable tools are used, because the casing is relatively free in the hole and there is less probability of accidental or unforeseen developments which prevent the carrying out of a prearranged program.

Having determined the necessary number of strings, the next consideration will be the size of drill with which it is desired to finish the well. This depends upon the nature of the oil-producing material, the productivity of wells in the region, the character of the oil and whether or not water or high-pressure gas is associated with it. There must be adequate clearance in the bottom of the well to accommodate a pump of the size necessary to handle the production expected. There must be, in addition, a moderate amount of space about the pump and well tubing in which oil may accumulate. In California, an effort is made to complete wells with a minimum diameter of 6¼ in., which provides adequate clearance and oil space for the operation of a 3-in. plunger pump, the size of pump commonly used. Many wells are finished with a smaller diameter than this, but it seems reasonable to expect that production is not so efficiently obtained from them. It will be shown in a later chapter, that the flow of oil from a saturated sand varies directly with the area of sand exposed in the well; which gives the advantage to the well of larger diameter, from the economic point of view as well as from practical operating considerations.

Having determined upon the diameter with which the well is to be finished, and the necessary number of changes in size of the casing, it is a simple matter with the aid of the tables giving casing sizes, and bearing in mind that each string must pass freely through the previous string, to determine the minimum sizes of the respective strings and the initial diameter of the well.[1] Table XXVII gives various combinations of

TABLE XXVII.—COMBINATIONS OF TELESCOPING PIPES USED IN CASING OIL WELLS

String No.	Combination number 1	2	3	4	5	6
1	20" -90# D. P.	20" -90# D P.	20" -90# D. P.	20" -90# D. P.	18" -81# D. P.	20" -90# D. P.
2	15½"-70# D. B. X.	17" -73# D. B. X	15½" -70# D. P	17" -73# D. P.	15" -61# D. P.	15½"-70# D. B. X.
3	12½"-50# D. B. X.	11⅝"-40# D. B. X	12½" -50# S. P.	14" -57# D. P.	11" -47# D. P.	12½"-50# S. P.
4	10" -40# D. B. X	9⅝"-33# D B X	10" -35# S P.	10" -42# D P.	9" -35# D P	10" -40# D. B. X.
5	8¼"-32# D. B X	7⅝"-26# D. B. X	8¼" -28# S P	8" -29# D P	7" -24# D. P.	8¼"-28# D. B. X.
6	6¼"-26# D B X.	5⅝"-20# D B X	6⅝" -24# S P	6" -19# D P	5⅝"-10# D P	6⅝"-24# S. P.
7	4½"-16# D B X	. . . .	5³⁄₁₆"-16# S P	4½"-13# D P.	4¼"- 7# D. P	

Abbreviations used: D. B X = Diamond B X casing, S P. = South Penn Casing, D P. = Drive Pipe

standard sizes of casings, showing sizes that telescope in the well with adequate clearance to insure free movement of the inner strings. The outer diameter of the collar on the inner string is the determining factor, though there should be provided in addition to the clearance for the collar, at least ¼ in. to insure free movement of the inner string and passage of the casing shoe. Combination No. 1 is commonly used in many American fields for deep-well rotary drilling, though in many cases the sizes larger than 10-in. can be dispensed with. Combination No. 1 is also a commonly used series for deep and moderately deep cable drilled wells. The thickness of the pipe walls of course influences the amount of clearance available, but the combinations given in the table provide sufficient clearance for the heaviest standard casings of each size used. Figure 114 illustrates a typical casing installation in which three strings of casing are used.

Collapsing Pressure of Casing.—It will be necessary in selecting casing to consider the external pressure to which the casing will be subjected, and choose a pipe heavy enough, or with walls sufficiently thick, to insure against its collapse. The collapsing forces may be either pressure from the walls of the well as a result of caving against the pipe, or hydrostatic pressure resulting from water or mud accumulating around a casing, from the interior of which it has been excluded. It is impossible to evaluate the forces developed as a result of earth

pressure, but the amount of hydrostatic pressure that may develop can be definitely calculated if all of the conditions are known. The hydrostatic pressure developed against the outside of a column of pipe by bailing down the well inside of the pipe after making a water shut-off, or by casing off a high-pressure water sand behind the pipe, may become a force of great magnitude, and is frequently sufficient to collapse the lighter weight casings. Suppose, for example, that water accumulates around a pipe to a depth of 2,000 ft. The maximum water pressure developed will be 43.4 × 20, or 868 lb. per square inch; and if the fluid is a mud of, say, 1.2 specific gravity, the pressure will be 1,042 lb. Boston casing 10 in. in diameter and .209 in. thick (9⅝-in. 22.75 lb.) will collapse under a pressure of 460 lb. per square inch. Even 10-in. 40 lb. California Diamond B X casing will collapse at 1,420 lb. per square inch, which would provide a safety factor of only 1.4 in the case of the 2,000-foot head cited above. In general, for the average oil well casing, under the severe conditions to which it is subjected, a minimum safety factor of 2 should be used in determining proper casing weights, and pipe manufacturers recommend a factor of 5 as preferable.

For calculating the collapsing pressures of lap-welded, bessemer steel casing, Stewart's formulae may be used:[6]

$$P = 86{,}670 \frac{t}{D} - 1{,}386 \qquad (1)$$

and

$$P = 50{,}210{,}000 \left(\frac{t}{D}\right)^3 \qquad (2)$$

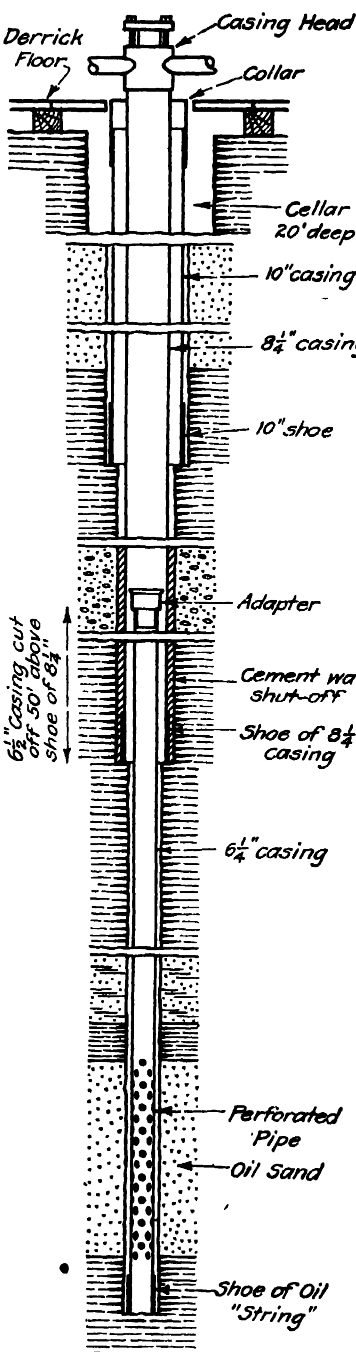


FIG. 114.—Illustrating manner of casing a well with three "strings" of pipe.

in which P is the collapsing pressure in pounds per square inch, D is the outside diameter of the tube in inches and t is the thickness of the wall in inches. Formula (1) is used for values of P greater than 581 lb. per square inch, or for values of t/D greater than .023; while formula (2) is for values less than these. Table XXVIII gives average collapsing pressures for steel tubes of different diameters and thicknesses.

TABLE XXVIII.—COLLAPSING PRESSURES AND CAPACITIES OF OIL WELL CASING‡

Nominal size, in.	Weight per ft with collars, lb.	Actual outside diameter, in.	Actual inside diameter, in.	Thickness, in.	Collapsing pressure per sq in., lb	Equivalent water column, ft.	Water column with safety factor of 2	Capacity per linear ft., U S gal.	Capacity per linear ft, cu ft	Capacity per 100 lin. ft., bbl
4¼	16	4 750	4.082	.334	4,710	10,850	5,425	.6792	.0908	1 62
4½	9.5	4.750	4.364	.193	2,140	4,920	2,460	.7702	.1039	1.83
4½	13	5.000	4 506	.247	2,900	6,680	3,340	.8281	.1107	1.97
4½	15	5.000	4 424	.288	3,610	8,320	4,160	.7982	1067	1.90
4¾*	8	5.000	4.696	152	1,250	2,880	1,440	.8997	.1203	2 14
4¾	13	5.000	4.500	.250	2,950	6,790	3,395	8262	1104	1.97
4¾	15	5 000	4.408	296	3,750	8,630	4,315	7928	1060	1.89
5†	16	5 250	4 648	.301	3,580	8,260	4,130	8814	.1178	2.10
5 3/16†	13	5 500	5 044	228	2,210	5,090	2,545	1 0380	.1388	2.47
5 3/16†	17	5 500	4 892	.304	3,400	7,840	3,922	9764	.1305	2 32
5⅝	20	6 000	5 352	324	3,290	7,580	3,790	1 1677	1561	2 78
6¼†	13	6 625	6 257	184	1,020	2,350	1,175	1 5973	2135	3.80
6¼†	17	6 625	6.135	.245	1,820	4,190	2,095	1 5356	2053	3 66
6¼	20	6 625	6 049	.288	2,380	5,480	2,740	1 4916	1994	3.55
6¼	24	6 625	5.921	.352	3,220	7,420	3,710	1 4295	.1911	3 40
6¼	26	6 625	5 855	385	3,650	8,410	4,205	1 3974	1868	3.33
6¼	28	6.625	5.791	.417	4,070	9,380	4,690	1 3667	1827	3 25
6⅝	17	7.000	6.538	.231	1,470	3,400	1,700	1 7440	.2331	4 15
6⅝	20	7.000	6 456	272	1,980	4,560	2,280	1 6988	.2271	4.04
6⅝	24	7.000	6 336	332	2,730	6,280	3,140	1 6379	2190	3 90
6⅝	26	7.000	6.276	.362	3,100	7,140	3,570	1 6061	.2147	3.82
6⅝	28	7 000	6.214	.393	3,480	8,020	4,010	1 5739	2104	3 75
6⅝	30	7.000	6.154	.423	3,850	8,870	4,435	1 5440	.2064	3 68
7⅝	26	8 000	7 386	.307	1,940	4,470	2,235	2 2240	2973	5 30
8 °	32	8 625	7.917	.351	2,170	5,000	2 500	2 5572	3419	6 09
8¼	28	8.625	8 017	.304	1,670	3,850	1,925	2 6204	3503	6 24
8¼	32	8.625	7 921	.352	2,150	4,950	2,475	2 5583	3420	6 09
8¼	36	8 625	7 825	.400	2,630	6,060	3,030	2 4962	3337	5.94
8¼	38	8 625	7.775	425	2,880	6,640	3,320	2 4648	.3295	5 87
8¼	43	8.625	7.651	487	3,510	8,090	4,015	2 3863	.3190	5 68
9⅝	33	10 000	9.384	308	1,280	2,950	1,175	3 5899	4799	8 55
10	40	10.750	10.054	.348	1,420	3,270	1,635	4 1210	5509	9 81
10	45	10.750	9.960	395	1,800	4,150	2,075	4 0140	.5406	9 63
10	48	10 750	9.902	.424	2,030	4,680	2,340	3 9976	.5344	9.52
10	54	10 750	9.784	.483	2,510	5,780	2,890	3 9026	.5217	9.29
11	47	11.750	11.000	.375	1,380	3,180	1,590	4.9334	.6595	11.74
11	60	11 750	10 772	489	2,220	5.120	2,560	4.7307	.6324	11.26
11⅝	40	12.000	11.384	308	840	1,940	970	5 2827	.7062	12 58
12½	40	13 000	12.438	.281	500	1,150	575	6 3083	.8433	15.02
12½	45	13.000	12 360	.320	750	1,730	865	6 2298	.8328	14 83
12½	50	13 000	12 282	.359	1,010	2,330	1,165	6 1497	8221	14.04
12½	54	13 000	12.220	.390	1,210	2,790	1,395	6.0869	.8137	14.49
13½	50	14 000	13.344	.328	640	1,470	735	7.2598	.9705	17.29
15½	70	16.000	15.198	.401	790	1,820	910	9.4150	1.2586	22.42
19 9/16	90	20.000	19.182	.409	430	980	490	15.0120	2.0068	35.74

* 14 thread. †11½ thread. °8 thread drive pipe; unless otherwise indicated, pipe is 10 thread.
1 U. S. gallon equals 231 cu. in.; 42 U. S. gallons equal 1 bbl. ‡ After F. B. Tough.

Inserting Casing

In the case of a well drilled by rotary tools, no casing is inserted until the particular size of hole being drilled is completed. When the hole is drilled to its full depth, the casing will be lowered as rapidly as possible, and "landed" on bottom or cemented to exclude water, after which drilling is continued with a smaller sized bit. With cable tools, a somewhat different procedure is followed in that the casing is often installed joint by joint as the hole is deepened. This is not necessarily the case when drilling in hard rock where the walls will "stand up" for depths of hundreds of feet without casing. In softer rocks which have a tendency to cave, however, the casing must be lowered progressively as the well is deepened, keeping the casing shoe but a short distance above the bit. When the cable tools are used it is a poor plan to let the rope socket or jars extend below the casing shoe, because of the danger of the tools falling to one side and getting the upper end caught behind the shoe. However, the cable tools cut a larger hole if permitted to drill 20 or 30 ft. ahead of the shoe, and for this reason the casing is usually suspended at about this distance off bottom unless there is danger to the casing or the tools by so doing.

Inserting Stove Pipe.—If riveted casing is used at all in the casing of a well, it is invariably the first string of pipe placed. The hole is left uncased as the well is "spudded in" and until such time as the walls show a tendency to cave. The "starter joint" of the stove pipe string, on the bottom of which a light steel shoe is often riveted, is then started into the well, and as it is lowered, additional sections are attached, picking or riveting the joints so that they do not pull apart. The column of pipe in the well is supported meanwhile by a pair of wooden clamps or friction blocks securely bolted around the pipe and supported either on timbers placed on the derrick floor or by wire line slings from the casing hook. The column is lowered or raised with the calf wheel. A pair of drive clamps on the drill stem may be used to drive the new joints lightly, until they telescope to the desired degree.

Not more than about 200 ft. of stove pipe can be lowered into an open hole, if it hangs freely without contact with the walls, without danger of the picked joints pulling apart. Usually, however, the pipe makes contact here and there with the walls so that wall friction may be counted upon to aid in holding the string together. Indeed, the friction developed is often so great that light driving is necessary to force the stove pipe into the hole. In cases of extreme friction, the hydraulic jack may be called into service to force the column down.

If stove pipe is to be inserted into an open hole more than 200 ft. deep, it is better practice to support the column from the bottom while it is being lowered, rather than at the top. In this case, it is lowered on a smaller string of screw casing or tubing, and is supported at or near its lower end by a cast-iron bushing or a casing spear attached to the lower end of the tubing. If a bushing is used, it is connected with the tubing by a left-hand thread, which, after the string of casing has been lowered to bottom, can be detached by rotating the tubing. After serving its intended purpose, it is easily broken up in the well with the drilling tools. The hold of the casing spear can also be broken by rotating the tubing, but in this case the tool is removed from the well with the tubing. In this way 500 ft. of stove pipe may be lowered into a well without injury to the casing and without danger of pulling it apart.

Usually the stove pipe string will be carried to some predetermined depth if the stratigraphy is known, if not, to as great a depth as possible; though the limitations previously mentioned in describing this type of casing preclude its use to depths in excess of 800 or 1,000 ft. under ordinary conditions.

When a depth is attained beyond which it is undesirable or impracticable to carry the stove pipe string, its shoe will be grounded, if possible, in some hard stratum, so that there will be no danger of the column sinking further into the hole during subsequent drilling operations, under the influence of its own weight. After "landing" the stove pipe string in this way, or after it has become permanently frozen, the top is cut off level with the casing sills in the cellar, so that it will not interfere with manipulation of smaller strings of pipe, and preparations are made to continue drilling with a smaller size of drill. Second and later strings of casing are nearly always of screw pipe, stove pipe being more difficult to handle at depth because of its tendency to pull apart. Then, too, it is not of sufficient strength to withstand the pressures to which it is ordinarily subjected in deep-well service.

Inserting Screw Casing.—In starting the second string of pipe, which, we will assume, is to be a large size of screw casing, a casing shoe is placed on the bottom of the first joint and the joint is lowered through the casing spider into the well with the elevators and hoisting block, until the open collar on the upper end is about 3 ft. above the derrick floor. The spider slips are then dropped into position about the pipe and the weight of the casing transferred from the elevators to the spider. The elevators are then freed and attached under the collar of a second joint of pipe, which has meanwhile been brought into the derrick from the casing rack. Power is then applied to the calf wheel, lifting the new joint of casing into the derrick with the collar end uppermost, until the lower end swings above the joint in the well. The thread protector on the lower end of the new joint is then removed and the threads thoroughly cleaned of rust, scale and dirt, with a wire brush, after which a suitable lubricant is applied.* Similar treatment is given the thread in the upper end of the collar on the joint of casing already in the well. The new joint of pipe is then lowered into the collar on the first joint, and a snubbing rope is applied to turn the upper joint by hand until the threads engage in the collar. The swivel hook above the elevators allows the casing to turn readily, while the spider prevents the casing in the well from turning. The casing tongs are then applied and the upper length of pipe turned as far as possible by hand, after which a jerk line is run from the tong handle to the crank, or to one of the rotary cat-heads, and the engine power is used to securely tighten the joint. With the tongs gripped about the pipe, if the cable tool rig is employed, each revolution of the crank turns the casing through about a quarter revolution, the tongs being rapidly swung back as the jerk line slackens on the upper half of the arc of the crank, for a new grip on the pipe. After the joint is securely tightened, the tongs are removed, the column of pipe is lifted far enough to release the slips by applying power to the calf wheel and after removing the slips from the spider, the column is lowered until the collar on the upper end of the new joint is about 3 ft. above the derrick floor. This process, as outlined, is repeated for each joint of pipe added to the column in the well, until the casing shoe is within 20 ft. of resting on bottom.

If cable tools are to be used, drilling is then resumed, the column of casing being suspended on the spider with the upper end but a short distance above the derrick

* The following formula is recommended for use in preparing a lubricant to be used on casing threads: tallow, 200 lb.; white lead ground in oil, 300 lb.; graphite, 24 lb.; lard oil, 30 gal. The lead is mixed with one portion of the oil, and the graphite with a second portion. The tallow is next melted and all ingredients then stirred together in a suitable container until thoroughly mixed.

floor, so that it does not interfere with the play of the temper screw. The spider is often lowered to the bottom of the cellar so that the upper end of the casing can be kept below or level with the derrick floor, and thus be out of the way of all operations in the derrick. As the hole is deepened, drilling will be interrupted occasionally to add more casing to the column, so that the shoe is always kept below the jars. The advantage offered by the casing spider, of being able to lower the casing gradually as drilling proceeds, is often helpful in shutting out a caving formation, allowing the tools to work on bottom without interruption.

Inserting Casing by Welding Joints.—The process of inserting a string of pipe, the joints of which are oxyacetylene-welded, is necessarily quite different from that described above for collared-joint casing. The pipe must first be prepared for welding. As already explained, plain-end pipe is used, and unless it is properly beveled for welding in the mill where it is made, each joint must be placed in a lathe, machined to square ends and then beveled on the outside for two-thirds of the thickness of the pipe. In order to reduce the number of welds made in the derrick, the pipe is welded into two-joint stands and three or four lugs are welded on the outside of each stand near one end, so that the elevators may be used in suspending it in the derrick.

The first stand is hung in the well on slips, either in the rotary table or a casing spider, and a rod of welding iron, bent into a U-form, is laid across the upper end.[4] The next stand has meanwhile been hoisted into the derrick on the elevators, and is lowered on the U-shaped rod, which serves to space the two joints at the proper distance apart for welding. Spacing of the ends in this way leaves room for expansion, so that the casing will not be thrown out of alignment when making the weld. Two welders work on opposite sides of the pipe, an arrangement which also aids in preventing crooked pipe as a result of unequal expansion. After the casing is aligned, two "tacks" are spot-welded on opposite sides of the joint, after which the welding metal is fused, beginning at positions 90 deg. from the tacks. The space between the square ends of the joints is first filled with metal, after which the corners of the beveled portion are rounded off to increase the surface of contact, and the space between the two joints is filled flush with the outer cylindrical surface. After the weld is completed, the lugs on the lower joint are cut off with the cutting flame, the weld is allowed to cool and the casing is lowered on the elevators for the next weld. Another type of welded joint makes use of a short reinforcing tube spot-welded on the inside of the joint.

With 8¼-in. casing, about 1 hr. is required for each weld (*i.e.*, for each 40-ft. stand). Welding saves about $5 per joint (for 8¼-in. pipe), by eliminating collars and threads, but this is partially offset by the cost of beveling the ends for welding. The extra cost of labor and materials used in welding, however, about equalizes the saving effected. Eight hours is necessary to run in 300 ft. of 8¼-in. pipe, as against 1½ hr. for a like amount of screw casing. Two welders, one helper and a drilling crew of five men are necessary in conducting the work, while steam supply, oxygen, acetylene, welding iron, etc., must also be taken into account. In the case of a well equipped with a welded liner in one of the California fields, the additional labor and materials amounted to about $75.

It is claimed that welded liners will stand more jarring and pulling than collared joints without danger of parting, do not freeze so readily and there is less loss of working space in the well because of elimination of the collars. In removing a welded liner from the well, it must be cut apart in stands of convenient length. This may be done with the cutting torch, but is preferably accomplished with pipe cutters which leave the ends straight and properly beveled for welding when the string is replaced.

Landing Casing.—When a string of pipe has been carried to as great a depth as is necessary, or as is deemed desirable, and a change in the diameter of the bore is to be made, the casing must be properly supported so that it will not follow down the hole under the influence of its own weight, during subsequent drilling operations. If possible, a stratum of hard rock will be selected in which to "land" the column of pipe, and a slightly smaller hole will be drilled a few feet ahead, into which the casing shoe will be driven. When the change is made to the smaller size of bit to be used in drilling the next section of hole, the casing will be supported on a narrow shoulder of hard rock, and with the shoe thoroughly embedded in it (see Fig. 137).

Cementing Casing.—If a string of pipe is to be used to exclude water, the procedure is somewhat different. The method of landing the pipe described in the preceding paragraph may be successful in excluding water (see "Formation Shut-off" on page 269), but most operators prefer to exclude water by surrounding the casing at its lower end with a plug of cement, which completely fills the space between the casing and the walls of the well. The cement is placed, by methods to be described in detail in Chap. IX, with the casing shoe a few feet off bottom; but the shoe is lowered to bottom and driven into a tight hole previously prepared for it, before the cement has taken its initial set. This leaves a few feet of cement which must be later drilled out of the casing. A period of from 10 to 16 days is usually allowed for the cement to harden before drilling is resumed.

Perforating the Oil String.—The last column of casing to be placed in the well is that which penetrates the oil sand, and is therefore called the "oil string" or "liner." This pipe must be perforated with a series of round holes or slots, opposite the oil-producing stratum, in order to admit the oil to the pump. The pipe may be perforated in the shop before lowering it into the well, or the openings may be made in the well with the aid of a casing perforator. The methods of perforating casing, the placing of screens and other details incidental to the completion of the well and preparing it for production, are to be described in Chap. XI.

Salvaging Pipe in Casing a Well.—It is not necessary that all strings of casing in a well come to the surface. Unless water is to be excluded by a column of casing, it may be cut off about 50 ft. above the shoe of the preceding string, and considerable casing salvaged (see Fig. 114). A "water string," however, must always extend to the surface so that water may not accumulate behind it and overflow into the lower part of the well. A string of pipe which is not intended to extend to the surface may have placed in it at the proper point a "bell collar" having left-hand threads in one end, so that by rotating the column of pipe after the shoe has been placed on bottom, the column is broken at the bell collar and the upper end is removed. Casing may also be cut at any desired

point by the use of a tool made for the purpose and called a "casing cutter" (see Fig. 121).

DIFFICULTIES ENCOUNTERED IN HANDLING CASING IN THE WELL

Casing difficulties are the result of either freezing, collapsing, telescoping, parting or splitting. Freezing results from caving of the walls against the pipe, accumulation of mud around the casing collars, contact with the walls in a crooked hole or failure properly to ream a tight place in the well. Collapse of the casing is due to external pressure, generally hydrostatic pressure; though caving of the walls or a loose bowlder in the walls bearing against the pipe as it is forced down may deform it. Telescoping of a column of pipe may result from dropping it accidentally, or in the case of stove pipe, by driving it too severely at the top when the lower end is frozen. Parting, or pulling apart of a column of pipe, may be the result of extreme tensional strain engendered by its own weight or by trying to pull it up when it is frozen. It may result from defective threads or from failure to couple the joints properly; or the lower end of the column may be loosened by turning the pipe in the well, or by the jar resulting from hammering on its upper end in driving it down. A column of stove pipe often pulls apart by failure of the picked joints to hold together. Premature explosion of a charge of dynamite or nitroglycerin will generally part the casing opposite the point of explosion. Splitting of casing usually indicates defective welding in the manufacturing process, but it may be caused by drilling out material which has "heaved" up from the bottom into the casing, or it may result from the use of a swedge, casing spear or other fishing tools (see pages 237 and 238). Most of these difficulties may be avoided by proper selection and inspection of casing and care in coupling the joints together and lowering the column into the well. Good judgment is also necessary in determining to what depths a string of pipe may be carried under the conditions applying, and what strain can be safely put upon it. The condition of the walls of the well, whether or not the hole is crooked, or if all tight places have been adequately reamed, will also have an important bearing on the success of a casing installation.

Freeing Partially Frozen Casing.—If the casing develops frictional contact with the "formation," that is, if it shows indications of being collar-bound with mud and loose material from the walls, it can often be freed by alternately raising and lowering a few times for a distance of 20 or 30 ft., working the loose material past the collars and shoe so that it falls into the bottom of the well.[3] If this fails to relieve the friction on the pipe, the well may be bailed down within the casing so that hydrostatic pressure aids in clearing the space about the pipe; or a hole may be drilled ahead of the casing shoe so that there is adequate space

into which the mud may flow. The pressure conditions may be reversed by placing a circulating head on the top of the casing and pumping water down through it under pump pressure in the hope of establishing circulation back to the surface through the space around the pipe. If circulation can be established, the mud will be gradually removed by the upward current. If difficulty is found in securing circulation under the pump pressure available, a slit cut in the casing shoe or in the pipe immediately above is often effective.

If friction on a column of casing is due to an effort to lower it through too small a hole, the best remedy is to pull the pipe up until the shoe is above the tight place, and under-ream it thoroughly. Under such conditions, particularly if the pipe has been driven, it is often impossible to lift the column against the friction with the power available from the calf wheel and hoisting blocks, or without placing undue strain on the derrick. In such a case a combined pull and jar is often successful where a simple pull fails. This is accomplished by lowering a casing spear (see description of spear on page 238) below the stem and a pair of fishing jars, taking hold with the spear inside of the pipe near the bottom, and jarring up with a long stroke of the beam. Tension is meanwhile held on the casing with the hoisting blocks and elevators (see Fig. 116), or a lifting force may be applied to the casing by means of screw or hydraulic jacks.

Driving Casing.—If friction on the pipe is thought to be due to a crooked hole, or if it has been gradually increasing and the landing depth selected has been almost reached, the pipe may be driven from the surface, in the hope of reaching the required depth before the pipe becomes completely frozen. Alternate driving and pulling of casing is also effective in freeing it from wall friction. Driving the casing down will often leave a free space above the collars, so that the pipe can be readily drawn back the same or, often, a slightly greater distance. Alternate driving and pulling back in this way will in many cases gradually free frozen casing until it can be moved up and down the length of a joint of pipe, when it should pull quite freely. In driving casing, "spring" and "vibration" of the pipe are the means of loosening the enveloping sediment. The method of driving casing from the top with the drive clamps and head has already been described. Driving from the top is likely to be detrimental to the pipe, often loosening the joints, or in some cases stripping threads in the collars; furthermore, much of the force expended at the top of the column is absorbed at depth by the elasticity of the pipe.

A long column of pipe can be driven more satisfactorily by applying the vibration near the bottom instead of at the top.[3] This can be accomplished through the use of the jar-down or drive-down casing spear. The tools are strung as in fishing (see page 239), with long-stroke fishing jars below the stem and with the spear screwed on the bottom of the lower link of the jars. The slips on this spear are so constructed that they slip up a conical recess and out against the inner face of the casing, preventing the tools from going farther down the hole. The process of driving down with this equipment consists simply in gripping the casing with the spear at the desired depth and operating the walking beam with a stroke sufficient to cause the jars to strike on the down stroke. The position of the spear must be changed frequently to prevent the pipe from becoming distorted by the outward pressure of the spear slips.

Lubricating Casing with Oil to Reduce Friction.—Observation has shown that pipe will freeze less readily in rocks saturated with oil, and in some instances petroleum has been circulated in wells with the hope of reducing friction of the walls against the pipe. This method has apparently met with some success in certain California fields where it has been found possible, by circulating oil, to keep a long string of pipe fairly free in the well, while ordinary unlubricated casing in the same territory freezes rapidly. It seems probable that the oil saturates the material in the walls, rendering them more plastic, thus releasing the hold on the pipe. Furthermore, loose sand, which tends to pack about the casing collars in the presence of water, remains in suspension in oil. Casings, apparently firmly frozen, have been released by circulating oil with pump pressure under the shoe and back to the surface. In one case a column of 12½-in. casing was frozen in a 15-in. hole and the derrick was "pulled in" in attempting to release it. After the derrick had been rebuilt, oil was circulated for 3 days and the string was readily pulled out.[2]

The dangers involved in pulling on frozen casing are well understood by most drillers. When one considers the enormous mechanical advantage of the ordinary band wheel, calf wheel and hoisting block combination—ordinarily about 144 times the lifting force of the engine—it is apparent that we are dealing with a force of great magnitude, sufficient either to pull the pipe apart or collapse the derrick. Many men have been killed or injured by the collapse of the derrick or by contact with the calf line, hoisting blocks or elevators in the sudden release of tension when the casing pulls apart near the surface. The equipment should be operated from the engine house in pulling casing.

Parting and "Sidetracking" Frozen Casing.—Should it become impossible, by any of the methods suggested above, to move the pipe either up or down in the hole, and it is essential to continue to a greater depth with the size of pipe in use, the pipe must be parted above the point at which it has become frozen, and the lower end "sidetracked." It is possible to locate approximately the depth at which the pipe is frozen by lowering a fishing string and jar-down spear, taking hold inside of the pipe at intervals, jarring, and noting the change in character of the vibrations produced in the pipe. When the spear takes hold above the "friction," the jarring produces a metallic ring in the pipe that is quite absent when the spear is attached below. Knowing the approximate depth at which the casing is bound, it may be cut with a casing cutter, or ripped with a casing slitter or perforator, and pulled apart a short distance above; or, it may be parted with a charge of dynamite or nitroglycerin. The explosive should be used in small quantities—10 to 15 lb. of 40 per cent dynamite is sufficient in most cases. The upper end of the column of pipe may be withdrawn after parting by either of these methods, a new shoe placed on the bottom and the column replaced until the new shoe is about 75 ft. above the top of the parted string. The lower part of the well is then redrilled, proceeding cautiously until the detached column of pipe is passed.

"Sidetracking" Casing.—When a portion of a string of pipe has been either accidentally or intentionally parted, and it is found to be impossible for one reason or another to remove it from the well, an effort must be made to drill past the parted string. This may be a difficult procedure in hard rocks, but is easy of accomplishment in soft formations. Since it is necessary for the new casing to make a slight bend in passing the old pipe, an effort should be made to enlarge the hole by underreaming for a distance of 60 or 75 ft. above the top of the parted pipe.[3] The drilling tools are then put to work as in ordinary drilling, upon the top of the old pipe, gradually battering and distorting it until the tools work off to one side. Difficulty is often encountered in getting the new casing shoe to pass the top of the old pipe, but turning the string at the surface will often allow the shoe to slip past. Once by the upper end of the parted column, little difficulty results, the new hole being drilled at

one side of the parted column and the latter eventually cased off. Contact between the collars or ragged edges on the parted string and the shoe on the new string may cause slight delays, but patience in manipulating the casing at such times will usually overcome the difficulty. Various types of reamers and eccentric bits are used by some drillers in sidetracking pipe to aid in enlarging the hole and clearing the way for the new pipe. Often, better progress is made in drilling by the old pipe than in drilling the original hole. In some cases, hundreds of feet of casing are successfully sidetracked in this way, and occasionally several separate sections of pipe will be cased off in a single well. The method described may also be employed in sidetracking lost drilling tools or other well equipment impossible to recover by fishing.

Operations involved in the repair or replacement of collapsed, telescoped or parted casing partake of the nature of "fishing," and are reserved for description in Chap. VIII devoted to "Fishing Tools and Methods."

Measuring Casing: *Stretch and Sag in a Column of Pipe.*—It is occasionally necessary to know the exact length of a string of pipe, or the precise depth at which the shoe of the string is located. The repair of old wells, the exclusion of water occurring in strata immediately above an oil sand or the depth at which to place perforated pipe, detonate explosives or apply casing cutters or other special tools, are operations which often require fairly exact casing measurements. In order that such information be available, it is a good plan to record it as a part of the log of the well (see page 57), which is carefully preserved as a record for future reference.

While it is possible to determine approximately the length of a column of pipe by measuring each joint that goes into it (length from top of collar to top of lower threads), the sum of such measurements will seldom give the exact length of the column due to variation in the length of threaded ends in the couplings. A better method is to measure the length of each stand or joint with a steel tape after the joints have been "set up" with the tongs and are ready to be lowered into the well. Even such a measurement is not altogether reliable if it is to be used as a means of correlating with a stratigraphic record, say, in determining the precise depth at which to make a water shut-off, or to place perforated pipe opposite an oil sand. This results from the "stretch" of a column of casing under its own weight, which tends to make the column longer than the tape measurement would indicate; and the "snaking" of the pipe in the hole, which results in some cases in a considerably greater length of casing being placed in a hole than the actual drilled depth. An approximate calculation of the elastic elongation of a column of pipe hanging freely in a well, for example, indicates that 3,000 ft. (tape measured) of 10-in., 40-lb. pipe, would actually be 6 in. longer. Linear expansion in a column of this length subjected to an average increase of, say, 50°F. in ground temperature, will add another foot to the length of the pipe. It is a matter of common observation, in pulling a column of casing out of a deep well, that several feet, or, at times, even a joint

or more may be pulled up at the surface before the full weight of the pipe is felt. This can be nothing else than stretch in the pipe, or surplus pipe that results from "staggering" of the casing from side to side in the hole. Many drillers consider a stretch of 1 in. to 100 ft. a normal elongation in pulling frozen pipe. If a well departs from the vertical, by say 5 deg. in a depth of 3,000 ft., the bottom may actually be 12 ft. nearer the surface than the length of the pipe in the hole would indicate.

The actual depth to the lower end of a column of casing may be checked by an independent measurement after the column is in place in the well, if precise data are necessary. In such measurements, it is customary to lower some tool—such as a ripper, an under-reamer, a latch jack, or a specially designed hook—which can be made to catch on the lower edge of the casing shoe, carefully measuring the length of the cable on which the tool is suspended.[8] An under-reamer of the same size as the casing gives especially satisfactory results. The lugs expand after passing below the shoe, and on pulling the tool up so that the lugs strike against the shoe, the resulting vibration indicates definitely the position of the shoe.

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CHAPTER VIII

FISHING TOOLS AND METHODS

The recovery of tools, cables, pipe and rods that have become detached while in the well, or that have been accidentally dropped into the well, and the repair of damaged casing, are operations that require the highest skill and ingenuity of the driller. In many cases, the completion of the well hinges upon success in recovering the lost equipment or making the necessary repairs. Days, weeks or even months may be spent, and large sums of money expended in fishing operations.

A great variety of special tools have been devised to assist in such work, some of which are described and illustrated in the present chapter. Only the more common fishing tools will be discussed, and these but briefly, it being quite impossible, in the space available, to adequately describe all of the many tools that find application in fishing operations. Indeed, many of these tools are but rarely used; in some cases a tool will be made for a particular purpose and never used again. Only the largest operators can afford to own more than a limited assortment of such tools because of their great cost and limited use, and many operators make a practice of renting them from local supply houses as they are needed. The technic of fishing is mastered by comparatively few drillers, and the industry is developing specialists in this work, who undertake the recovery of lost tools or the repair of damaged casing under contract.

One might suppose that the loss or breakage of a tool in the well, or the parting or collapse of a string of casing, is the result of carelessness, and might be avoided by proper design and care in the conduct of the work. While this is true to a large extent, it must be recognized that such accidents are a natural hazard; that they are inherent from the very nature of the work, and therefore can never be entirely overcome. However, proper care in handling the equipment, and frequent and thorough inspection of cables, casing, drill stem, tools and tool joints will greatly reduce the number and frequency of fishing jobs. Drilling cables and sand lines should be watched carefully for signs of weakness or unusual wear; drilling tools, drill stem and casing should be inspected for incipient cracks, particularly at welds; and no tools or equipment should be lowered into the well unless, as far as can be detected, they are in perfect condition. In anticipation of the inevitable fishing job, it is a good plan to fully record the dimensions of everything lowered into the well, so that information will be at hand for designing or selecting a suitable fishing tool.

We may classify the various fishing tools to be described, according to the purposes for which they are intended, or the nature of the operations in which they are used. There is a large group of fishing tools designed for recovering various parts of the string of cable drilling tools; another group is intended chiefly for taking hold either on the inside or outside of hollow cylindrical objects, such as casing, bailers or rotary drill stem; still others are designed to expand, cut, rip or perforate casing; and there are also a number of tools used in recovering or cutting hemp rope or steel cable in the well.

REPAIRING AND RECOVERING DAMAGED CASING

The difficulties encountered in handling casing in the well were outlined in Chap. VII. The methods of releasing frozen casing were there discussed, but the methods of repairing collapsed, parted and punctured casing were deferred until the present chapter.

Collapsed Casing

Use of the Casing Swage.—Collapsed casing, which has been partially flattened, dented or otherwise distorted from its original cylindrical form, as a result of abnormal external pressure, can often be brought back to its original form by driving a casing swage through the collapsed section. Common types of casing swages are illustrated in Fig. 115. They have solid cylindrical bodies, pointed at the lower end, and equipped at the upper end with a tool joint for connecting with the lower link of the jars. A spiral groove or water course is cut in the cylindrical surface to allow the well fluid to pass as the tool is lowered down through the pipe. The maximum diameter of the cylindrical body of the swage is but a fraction of an inch smaller than the diameter of the casing for which it is designed; thus, casing with a 10-in. inside diameter should permit the passage of a swage 9⅞ in. in diameter.

The swage is attached below long-stroke fishing jars, and the latter is attached to the lower end of the drill stem.[1] The tools, thus connected, are lowered into the well until the swage encounters the collapsed or dented portion of the pipe. The weight of the tools is then transferred to the walking beam, the jars being permitted to telescope and strike on the down stroke. As the swage is driven ahead by the impact of the stem and jars, the temper screw is let out sufficiently to keep the jars striking on the lower end of the down stroke. When the swage has been driven through the collapsed section and has entered the undisturbed pipe below, the tools swing freely, resulting in an unmistakable change in vibration and cable tension. The swage must now be drawn back through the collapsed section, and will probably have to be jarred back by permitting the jars to strike on the upstroke. The swage should be driven down and back through the pipe until it can be pulled through without jarring.

When it is thought that the pipe is badly flattened, it is preferable to drive a swage of smaller diameter through first, and the full diameter of the pipe attained

through the use of successively larger swages. The swage sometimes becomes wedged in the casing, and if the pipe is split, either by the collapse or by the pressure of the swage, a most difficult situation may result through loose debris entering above the swage and wedging about it.

Recovering Parted Casing

When a string of casing has pulled apart in the well as a result of a defective joint, insufficient thickness of metal, severe tensional strain—as in attempting to pull it out of the well when the lower end is frozen—or when it has been purposely parted with the aid of a casing cutter, ripper or explosives, either of several different tools may be used in recovering the lower end. If the condition of the well and the casing permits of withdrawing the pipe to the surface to join the parted ends, this method is generally preferred, and for this purpose use may be made of either a casing spear, which takes hold inside of the pipe, or a casing bowl or overshot, which takes hold outside of the pipe. If there is reason to expect that the upper end of the parted column is splintered or irregularly fractured, as often happens when casing is parted with explosives, a mandrel socket may be preferable. If it is considered best not to remove the parted string from the well, connection may be made with it by a new string lowered from the surface, with a die nipple placed on the lower end.

Use of the Casing Spear.—There are many types of casing spears designed for taking a hold on the inside of a column of pipe, but they can all be classified into two groups: (1) bulldog spears, which have no mechanism for releasing the spear once it takes hold, and (2) trip spears, which may be readily released, either by turning the tubing on which they are lowered, or by driving down upon them with the fishing jars.

Common forms of casing spears are illustrated in Fig. 115. They consist usually of a substantial cylindrical steel body, pointed somewhat at the lower end to guide the tool into the pipe which it is to recover, and equipped with a pin joint at the upper end for connection to the fishing jars or drill stem. Inclined planes are machined out of the cylindrical body for either two or four slips, the slips operating in grooves and keyed to a mandrel extending up through the body of the tool. In the case of the trip spear, the mechanism controlling release of the slips must be built inside of, or below, or above the main body of the tool, and often consists of a spring device operated by a latch or trigger, which can be tripped by revolving the tool, or by driving down upon it with the jars.

In using a spear to recover parted casing, the tool is screwed to a mandrel and the latter is attached to the lower end of the jars.[1] If the spear to be used is of the bulldog type or a type of trip spear that is released by the jars, the fishing string thus assembled may be lowered on the drilling cable. If a trip spear of the type that is released by turning is to be used, it must be lowered on a string of tubing, and a substitute is used in connecting with the fishing string above the jars. When the tool has entered the open end of the parted pipe, it is raised until the slips slide down the beveled supports and bind against the walls of the pipe.

A trip spear should be used in preference to one of the bulldog type when there is any possibility of the casing being frozen or otherwise difficult to remove from the

well. A bulldog spear can be driven further into a pipe, but cannot be pulled out once it has been lowered, unless the pipe comes with it, without damaging either the spear or the pipe. Even the trip spears are apt to become "bulldogged" in the pipe by failure of the tripping mechanism to work properly, or by caving of material from the walls above. When it is necessary to break the hold of a spear, the slips can often be worn smooth by "hitching on" to the beam and jarring both up and down, rasping the slips against the pipe. Such action, however, is apt to damage the

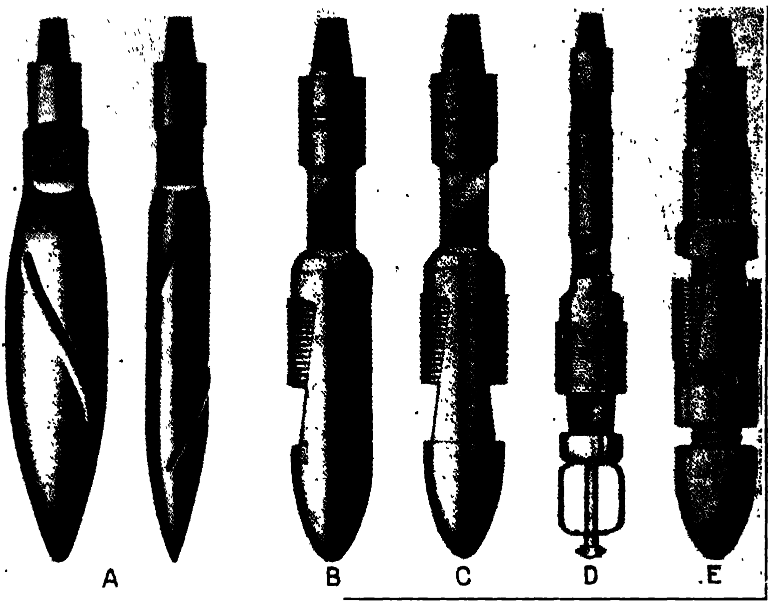
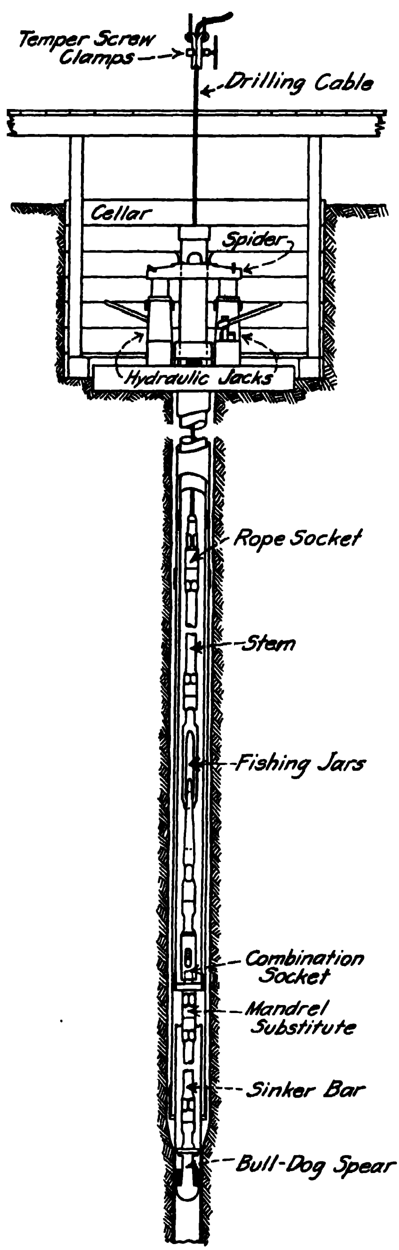


FIG. 115.—Types of casing swages and spears.

A, casing swages; *B*, bull dog single-slip spear; *C*, bull dog double-slip spear, *D*, drive-down trip spear and *E*, Fox trip spear.

pipe. In some cases the slips break and fall into the well so that the main body of the tool can be withdrawn. The slips can usually be broken off if necessary, in order to remove the tool, by driving the spear down until it passes below the casing shoe, and then jerking up so that the slips strike the lower edge of the shoe. Pressure of the slips against the casing is apt to cause bulging or splitting of the metal. For this reason, the position of the spear should be changed occasionally.

The use of a casing spear in jarring on frozen pipe has already been described (see page 232). A somewhat similar plan is occasionally followed when the lower end of a parted string of pipe has become frozen in the well (see Fig. 116). A spear is attached to the lower end of a short stem, and the latter is attached at its upper end to a substitute equipped with a mandrel projecting upward at its center.[1] The substitute is screwed into a casing collar, and the tools thus assembled are lowered on a column of casing of the same size as the parted string in the well. When the spear has entered the upper end of the parted section of pipe and has taken hold, two hydraulic jacks are rigged under the casing spider in the cellar, and tension is applied to the pipe. A second fishing string, consisting of a combination socket (see page 251), fishing jars, stem and rope socket, is then lowered on the drilling cable and a hold taken with the combination socket on the mandrel, which projects above the



(*After T. Curtin in U. S. B. Mines Bull* 182).
FIG. 116.—Fishing string for applying combined jar and pull on casing.

substitute. The latter string is then hitched onto the walking beam and the stroke adjusted so that the jars strike on the up stroke. This combined lifting force, or pull of the hydraulic jacks, and jarring action is often effective in freeing the casing.

In addition to its use in recovering casing, the spear may also be used in recovering a lost bailer the bail of which has pulled out, or rotary drill stem, well tubing or any hollow cylindrical object to the inside of which access may be had from above.

Use of the Casing Bowl.—The casing bowl is a hollow, cylindrical tool equipped with internally placed slips which can be lowered over a cylindrical object and a hold taken on the outer surface. One successful type of casing bowl (see Fig. 117) has three slender slips mounted in machined inclined grooves on the inner surface of a steel cylinder.[1] If the parted section of pipe has no collar on the top joint, a bowl of proper size can be lowered over the end and a hold taken sufficient to withstand considerable pulling. It may be used instead of a die coupling or collar (see page 242) in cases where it is desired merely to connect with a detached string of pipe in the well without pulling it out. This tool has not sufficient strength to permit of driving, and is not watertight.

Use of the Overshot.—If a collar has been left on or near the upper end of a parted string of casing, the overshot may be used in recovering it. This is a tool equipped with three flat springs held erect within a steel bowl (see Fig 117). It is suspended on the lower end of a column of pipe of greater diameter than the detached string in the well. As it is lowered, the bowl guides the tool over the upper end and the springs press inward against the parted string. It continues to descend, telescoping over the parted section of pipe, until the springs slip under the lower edge of a collar, when on pulling up on the tool a hold is taken sufficient to stand severe strain. The overshot is widely used in recovering rotary drill stem that has twisted off while in the well as a result of severe torsional strain, and is also useful in picking up tubing or casing that has been dropped and is broken or crooked.

Use of the Bell Socket or Mandrel Socket.—When casing has parted and the upper end of the detached column is ragged or fractured so that the tools described above are not effective, the mandrel socket may be used. This consists of a long, hollow, tapered, cone-shaped socket, through which extends a mandrel with an egg-

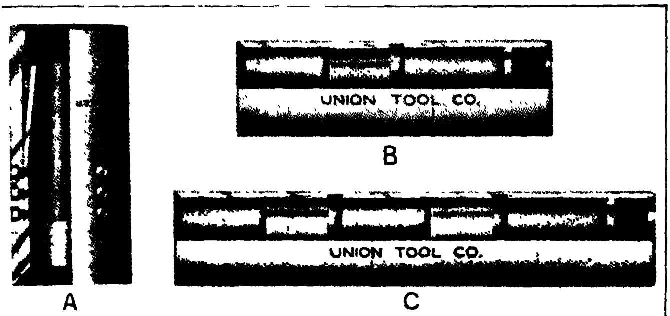


FIG. 117.—Fishing tools for recovering casing or rotary drill pipe. *A*, overshot; *B*, single-slip casing bowl and *C*, double-slip casing bowl.

shaped knob on the lower end. The mandrel is free to slide up and down within the socket, and on the upper end a pin joint is forged for connecting with the jars. A shoulder turned on the mandrel just below the tool joint, permits of driving down on the flattened top of the socket with the aid of the jars.

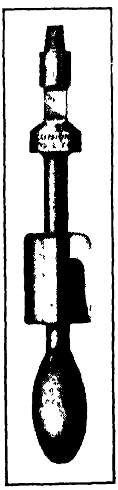


FIG. 118.—Bell socket.

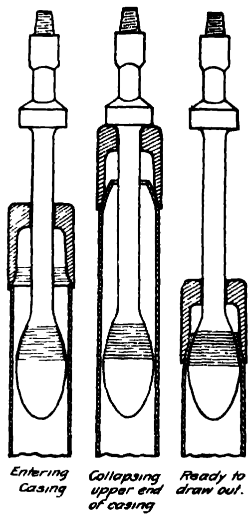


FIG. 119.—Illustrating application of bell socket.

As the tool is lowered below fishing jars and a drill stem on the drilling cable, the socket passes over and the mandrel inside of the detached column of pipe.[3] Driving down with the jars, with the mandrel extended below the socket as shown in Fig. 119, the upper end of the detached pipe is collapsed and forced into the conical socket, thus partially closing the end of the pipe. On drawing up the tools, the knob on the lower end of the mandrel, now too large to pass through, grips the collapsed

pipe on the inside and presses it against the inner face of the mandrel. The friction hold, thus secured, is sufficient to withdraw the pipe if it is free to come.

Use of the Die Nipple and Die Collar.—Steel die nipples and die collars are used to recut threads on a detached column of pipe in the well, and may also serve as a coupling after the connection has been established (see Fig. 120). The die nipple is designed to cut a thread on the inside of a pipe or inside of a casing collar, while the die collar fits over the pipe and cuts a thread on the outside. A combination nipple is designed to operate inside of the pipe on one end, and outside on the other. These tools are made of case-hardened tool steel, too brittle to stand driving, although

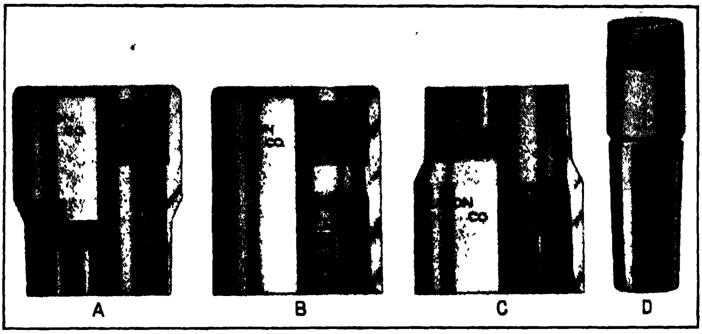


FIG. 120.—Die nipples, collars and tap for taking hold of parted casing. *A*, die nipple; *B*, die collar, *C*, combined die nipple and collar, *D*, fishing tap

considerable tension may be applied if pulling is necessary. Aside from their use in cutting threads, they may be left as a permanent coupling in a string of pipe if, for any reason, it is considered inadvisable to pull the pipe out of the well after a connection has been effected. Because of the vertical grooves left in the cutting teeth for the escape of metal cuttings, die nipples and collars are not watertight, and should not be left permanently in a water string. If a die coupling is to be used to couple two parts of a string of pipe permanently, care should be taken to select one large enough in inside diameter to pass the various drilling tools that must be subsequently lowered through it.

Die collars and nipples are lowered on the bottom of a string of pipe of the same size as the parted pipe to be recovered.[1] When the tool rests lightly upon the upper end of the detached column, the "fishing string" is turned slightly until the pipe drops into position and is ready for screwing. Pipe tongs are then applied to the fishing string, with the aid of a jerk line to the crank, the weight of the upper pipe being permitted to rest upon the detached pipe. As the nipple or collar is screwed on with the engine power, a second pair of pipe-tongs is used to prevent the pipe from springing back, as a result of torsional strain in the pipe when the slack comes in the jerk line with each revolution of the crank. A reference mark is made on the pipe near the derrick floor to note the distance that the pipe settles after screwing begins, this being a measure of the length of thread cut unless some of the couplings in the fishing string "take up." As the die makes headway, a continuous increase in power is necessary to turn it. The point at which to stop turning is always more or less uncertain, but may be inferred from the amount of tension on the tongs and the distance that the pipe has settled. The two strings of pipe are thus firmly fastened together and in condition to be pulled if desired.

Cutting or Parting Casing in the Well

Occasionally it becomes necessary to detach a section of pipe in the well. This is often done when a string of pipe becomes frozen and the lower part of the column must be sidetracked (see page 233); and in salvaging pipe during the casing of a well or in abandoning it, parting of the casing is commonly practiced. A column of pipe may be cut apart while in the well with a special tool, called a casing cutter, which is lowered through the pipe to the desired point, and applied against the inner walls; or slits may be cut in the pipe with a casing ripper until it is so weakened that it can be readily pulled apart; or a charge of dynamite or nitroglycerin sufficient to part the pipe may be detonated in the well at the desired depth.

Cutting Pipe with the Casing Cutter.—The casing cutter is very similar in principle to the ordinary plumber's pipe cutter, except that it is designed to operate from the inside of the pipe instead of on the outside. The casing cutter consists essentially of a heavy cylindrical steel body into which are mortised a number of sliding steel blocks on the outer edges of which small circular, disc-shaped wheels of steel are mounted (see Fig. 121). The latter revolve freely in a horizontal plane on small metal pins set in the outer ends of the sliding blocks. A tapered steel mandrel operates through a cylindrical hole through the axis of the tool in such a way that when the mandrel is pressed down, it bears against the inner ends of the sliding blocks, forcing them horizontally outward. The casing cutter is lowered, screwed to the lower end of a column of tubing, which must, of course, be small enough to pass freely through the casing to be cut.

Before lowering the cutter, the stretch should be taken out of the casing and a moderate tension applied and maintained by means of the elevators or casing spider. There should be enough tension in the pipe to cause the upper end to "jump" when the pipe is cut, thus indicating completion of the work to the operator. With the casing under tension, the cutter is lowered to the desired depth on its tubing. The mandrel is then connected to the lower end of long-stroke jars small enough to enter the tubing, and from two to four sucker rods (see page 345) are placed above the jars to give weight to the upper link. The mandrel, jars and rods, thus connected, are lowered on the sand line through the tubing until the tapered mandrel enters its recess in the casing cutter and encounters the inner ends of the sliding steel blocks that have been pressed in during the descent of the tool. The tubing is then turned by hand. The weight of the rods above the mandrel forces the blocks containing the knives out against the casing. Sometimes this weight is sufficient for the work, but when it is not and the cutter turns with so little effort that the operator is convinced that it is making little progress, the mandrel may be driven further into the tool with the aid of the jars, by raising and dropping the sand line, either by hand or with the engine power. The mandrel should not be driven between the blocks too tightly or the tubing cannot be turned.

Usually from 20 to 40 min. turning of the tubing will be necessary to cut the casing, the upper end jumping slightly when the operation is completed, because of the tension in the pipe. The mandrel and rods should then be pulled and the tubing gently raised until the sliding blocks containing the cutters are forced back into their recesses, when the cutter can readily be withdrawn to the surface.

Use of the Casing Splitter.—Lowered to the desired depth in a column of casing to be parted, the casing splitter or ripper may be applied in cutting vertical slits in the pipe. Such action greatly weakens the casing, particularly if applied to the joints

under the collars, so that the column can be readily pulled apart by applying moderate tension at the upper end.

The tool consists of a substantial steel body, through which a recess is cut for a pointed steel knife mounted on a sliding block which slides on a steel pin in two inclined grooves (see Fig. 122). A pin joint is provided at the top of the tool for connecting with a fishing string consisting of long-stroke jars, drill stem and rope socket. A mandrel extends down through the axis of the tool and is attached to the

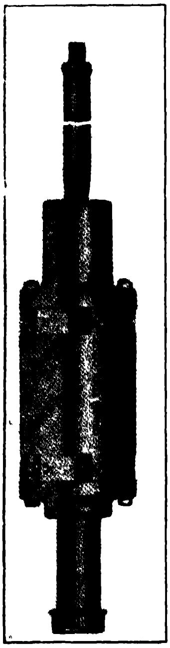


FIG. 121.

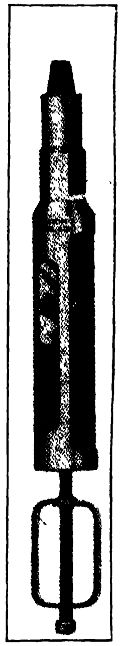


FIG. 122.

sliding block which supports the knife On the lower end of the mandrel a heavy spring is placed, which when released bears against the inner walls of the casing. There are single-knife and double-knife patterns, the latter type cutting two slots at once, 180 deg. apart on the circumference of the pipe.

Before lowering the splitter into the casing, the spring (see Fig. 122) is raised on the mandrel by compressing a small trigger at the lower end of the mandrel.[1] As the tool is lowered through the casing, there is enough pipe friction upon the spring to prevent it from dropping below the trip trigger. When the tool has been lowered to the desired depth, it is then raised a few feet, thus drawing the mandrel up through the spring; the mandrel trigger snaps into place above the lower edge of the spring and the tool is "tripped." The knife block is now held in the upper end of the inclined grooves by the spring pressure. The drilling cable on which the tools are lowered is then hitched to the beam, the play of the jars being adjusted so that they strike on the down stroke but not on the up stroke. With the first stroke of the jars the knife punches a hole through the casing, and succeeding blows will cause the knife to cut a slit vertically down the pipe. The progress of the knife will be retarded on encountering a casing coupling, but not stopped. A slight tension is held on the pipe while the tool is in operation. When a coupling is split, the pipe can

be readily pulled apart, although the coupling sometimes fails to spread enough to permit pulling without first driving down on the upper end of the column with the drive clamps and head. As the casing splitter is withdrawn, the knife block is forced down the inclined slots and away from the casing, compressing the mandrel against the spring. If necessary to effect withdrawal, the knife can readily be broken by driving up with the jars.

The casing splitter is commonly used in salvaging casing when a well is to be abandoned, and when the work involved in freeing an entire string of pipe would be too expensive. The tool may also be used for perforating pipe opposite an oil sand, though it is not as satisfactory for this purpose as a somewhat similar tool called a casing perforator. Casing perforators are described on page 320.

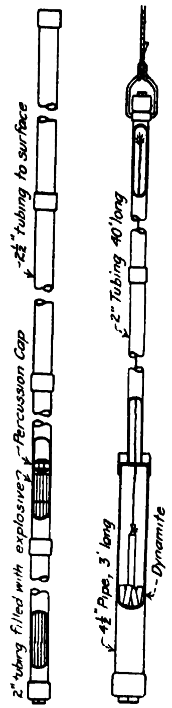
Use of Explosives in Parting Casing in the Well.—The simplest and cheapest method of parting a string of casing in the well is by the use of explosives. If a well is to be abandoned, the operator is anxious to salvage as much of the casing as possible at the lowest cost. An effort is first made to pull the casing. If it is frozen so that it cannot be readily pulled, explosives may be applied, parting the pipe a short distance above the shoe. If the casing still resists pulling, another shot may be fired some distance above the first, and blasting continued at successively higher points until the pipe can be pulled. Another frequent use of explosives in parting casing is found in freeing a water string from a cement plug when the shut-off has been unsuccessful. The lower end of the pipe may be shot to pieces so that the upper can be withdrawn and a new shoe attached. The lower part of the hole must then be redrilled, and a shut-off attempted at a lower horizon.

Either dynamite, blasting gelatin or nitroglycerin may be the explosive used, though blasting gelatin or ordinary stick dynamite are ordinarily preferred as safer and more reliable types of explosive than nitroglycerin. The explosive is charged into a suitable container or "torpedo," and is detonated with a blasting cap of fulminate of mercury, fired either electrically, with a fuse or squib or by the impact of a "go-devil" dropped from the surface. Electrical firing is safest, but a fuse or squib may be used with security if care is taken to make certain that the charge is properly placed and timed. The risks involved in handling explosives are appreciated by most operators, and it is customary to employ someone skilled in the use of explosives when such work is done. Often it is done under contract, by men who specialize in well shooting. The danger is not only to the workmen, but to the well also, for a premature explosion at some point above the desired horizon will wreck the casing, perhaps causing caving of the walls and burial of the well equipment, in some cases even necessitating abandonment of the well.

If dynamite is to be used, it must be lowered on the sand line to the desired point in a container made of casing or tubing.[1] From 20 to 40 sticks of 60 per cent dynamite are carefully packed into a piece of casing 4½ in. in diameter and 3 ft. long, with a coupling on each end and a plug in the lower coupling. In the top coupling, a 4½- by 2-in. bushing is placed to connect with two joints (about 40 ft.) of 2-in. tubing, which contains the fuse. A plug is placed in the top of the tubing so that the entire container is watertight. A small bail at the top provides a means of connecting with the sand line (see Fig. 123). A length of fuse is cut sufficient to allow ample time for lowering the explosive after lighting at the surface, and a detonating cap is crimped on one end and inserted in a stick of the explosive in the usual way. With the container charged with explosive and suspended in the well so that the top of the tubing is 2 or 3 ft. above the derrick floor, the squib is lowered through the tubing by means of the fuse until it rests upon the top of the explosive in the 4½-in. container. The fuse is then ignited, the plug screwed into the top of the tubing and the container with its charge is carefully lowered to the desired point in

the well. The explosive container and tubing will be shattered by the explosion, but the sand line will ordinarily be uninjured.

When it is desired to shatter a considerable length of casing, say, several hundred feet—as in shooting a section of cemented pipe—a string of 2½-in. tubing, plugged at top and bottom and as long as the section of pipe to be shattered, can be filled with explosive and detonated (see Fig. 123). In this case it might be preferable to fire the charge by means of a squib dropped upon the charge from the surface (see page 334).



(*After T Curtin in U S. B. Mines Bull* 182)
FIG. 123.—Illustrating use of tubing as dynamite container.

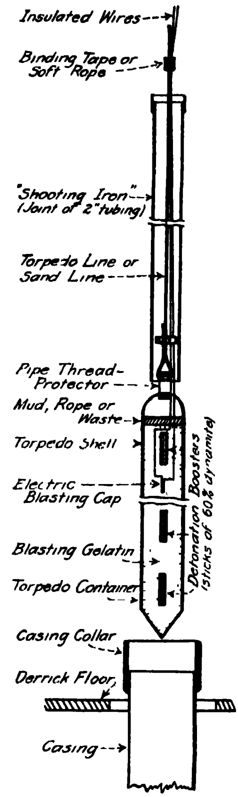


FIG. 124.—Illustrating manner of loading and lowering torpedo.

In firing electrically, the explosive should be placed in tubing or casing or in a torpedo shell, as described above, with an electric detonator on top of the charge (see Figs. 125 and 126). Two insulated copper wires connecting with the squib are carried through a watertight joint in the plug which encloses the top of the container, and are bound with cord or friction tape at intervals to the sand line on which the explosive is lowered. After the charge has reached the desired point in the well, the two wires are connected with a blasting machine or to a 2-pole switch placed in the lighting circuit, and the charge is fired. There is less danger of premature explosion when this method of firing is employed, and successful detonation of the charge is more certain than in firing by either of the other methods described above.

In the California fields,* most well shooting is done with blasting gelatin, which is less sensitive than 60 per cent dynamite, and therefore safer to use in practice. The blasting gelatin is carefully tamped into a cylindrical torpedo shell made of No. 28 galvanized sheet iron, with a few sticks of 60 per cent dynamite scattered through the charge to insure complete detonation of the gelatin (see Fig. 124). Electrical

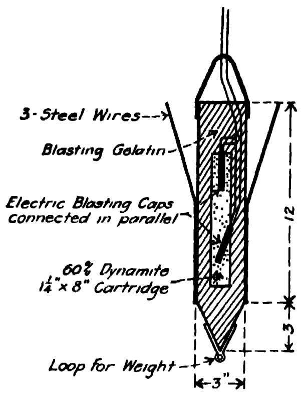


FIG. 125.—Hercules electric detonating squib.

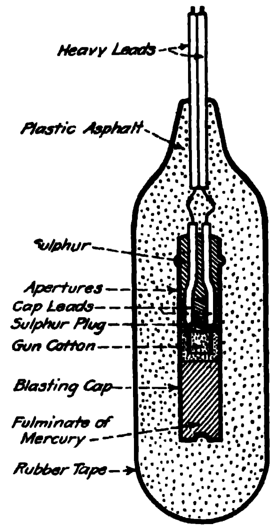


FIG. 126.—Allison electric detonating squib.

firing is preferred, a special 150-gr. fulminate of mercury cap being used for detonation. Generally more than one cap is used, in order to completely detonate the entire mass, one cap being used for every 3 linear feet of the length of the shell. The upper end of the torpedo should be closed with a pressure-resisting seal, to prevent compression of the gelatin, which, it is thought, may be the cause of premature explosions. A "shooting iron," consisting of a joint or two of 2- or 3-in. tubing, is suspended over the sand line, just above the torpedo, to prevent the line from being shot into a tangled mass by the explosion. The caps used are connected in parallel with the firing circuit, and symmetrically placed throughout the charge. The torpedo is usually lowered on the sand line, which forms one wire of the circuit, while an insulated copper wire bound to the sand line at intervals completes the connection with the blasting machine or electric circuit at the surface. If there is oil in the well, there is a possibility of the electrical connection with the sand line becoming insulated, causing a misfire, and for this reason some well shooters prefer to use two separate wires for the electrical circuit instead of depending upon the sand line to form one lead. Before the charge is lowered, and before firing, the circuits should be tested with a sensitive galvanometer and a silver chloride cell. The latter does not produce sufficient current to fire the caps, but as an added precaution, a suitable resistance is maintained in the circuit while testing.

Further description of the use of explosives in wells will be found in Chap. XI.

* GOLDMAN, F. and STEAD, G. D., Oil well shooting, a *thesis* prepared under the direction of the author, University of California, 1923.

RECOVERING STEEL AND HEMP CABLE

When the cable drilling tools are used, the drilling cable or sand line will occasionally break with the tools or the bailer in the well. If the break has occurred at some distance above the point of connection, the parted end will fall to the bottom in a twisted mass on top of the tools

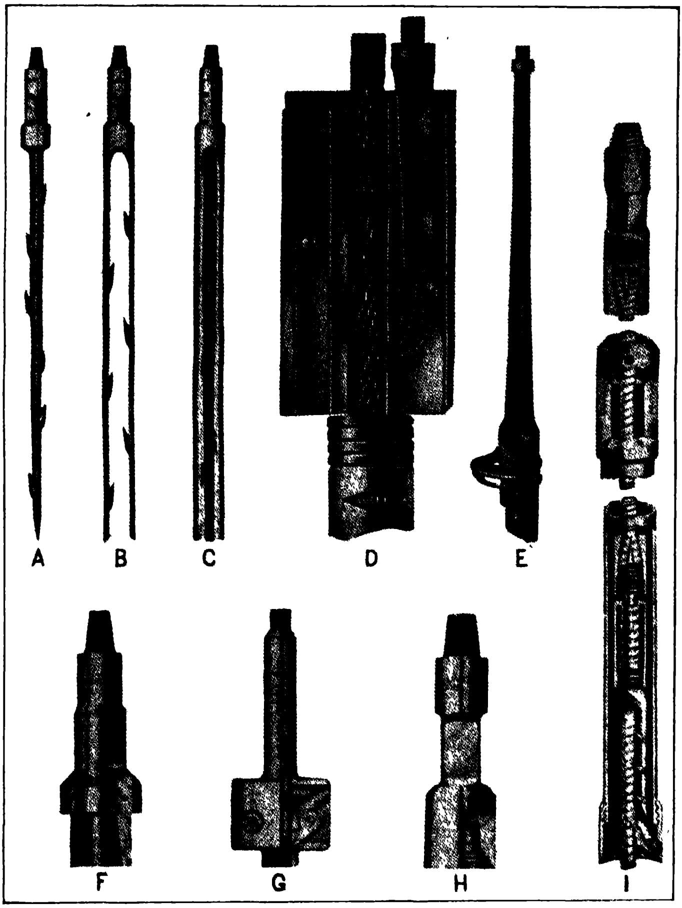


FIG 127. Tools for recovering drilling cable and sand line from the well.
A, rope spear, *B*, rope grab, two prong, *C*, rope grab, three prong; *D*, Spang wire-rope knife; *E* and *G*, other types of rope knives, *F*, rope spear wadder, *H*, blind rope chopper, *I*, Hecter's mouse trap.

or bailer, and must be recovered with the aid of a rope grab or spear. Occasionally, too, the drilling tools or bailer will become lodged in the well, either as a result of the walls caving or of the upper end of the string catching under the casing shoe. In such a case it may be necessary to cut the drilling cable or sand line in the well, directly above the rope socket or bailer bail, so that other fishing tools may have ready

access to the tools or bailer. For this purpose, various types of rope knives are used. The forms of rope grabs, spears and knives used will vary somewhat with the kind of rope to be recovered, that is, whether it is of manila hemp or steel wire.

Rope Grabs and Spears.—A group of representative rope grabs and spears are illustrated in Fig. 127. It will be noted that they consist of one or more prongs with a number of upturned, sharp-pointed "thorns" or spikes projecting from them. A pin joint at the top provides a means of connecting with a fishing string consisting of long-stroke jars, drill stem and rope socket. The tool is lowered and spudded up and down on the cable until the prongs and spikes take hold and the rope can be drawn to the surface. If the broken end of the cable is not long enough to reach to the surface, the hold of the spear is usually sufficient to support the tools or bailer, so that it can also be withdrawn. The "mouse trap," illustrated in Fig. 127, serves a similar purpose. This tool is lowered on three joints of tubing.[5] A few feet of cable will always enter the lower end, the small hinged wickers take hold and, as the upper part of the tool is pulled up, the rope is drawn into the tubing. Sixty-five feet of cable can be removed with each run.

Rope Knives.—If the bailer or tools become lodged in the well and it becomes necessary to cut the drilling cable or sand line to permit of access being had by tools employed in loosening them, one of several types of rope knives may be used. These knives vary from simple V- or hook-shaped bars with sharpened edges, or chisel and shear-shaped "choppers" used on hemp cable, to the stronger and more elaborate wire line knives which require the use of auxiliary jars and sinkers. The hemp knives and choppers are lowered with a sinker bar on the end of the sand line.

The resistant nature of steel wire cables requires a knife of greater strength and more positive manner of application. Such tools are usually lowered over the cable to be cut, and the knives are tripped or driven into cutting position on striking the rope socket or bailer bail. A common form (see Fig. 127-G) has one or more "dogs" with sharpened edges, so pivoted that they remain in a vertical position as long as the tool is being lowered, but fall into horizontal cutting position and bear against the cable as soon as they are raised. Another type (see Fig. 127-E) has a pivoted hollow disc, sharpened on the inner edge, which is held in horizontal position and free of the cable which passes through it, until tripped by contact with the rope socket or bailer. The disc-shaped knife then falls to an inclined position about the cable, and on drawing the tool up, the rope is sheared off. Still another type (see Fig. 127-D) is equipped with a curved knife on a steel mandrel, which is driven into cutting position with the aid of a sinker bar and a light pair of jars lowered on the sand line.

RECOVERING PARTS OF THE STRING OF CABLE DRILLING TOOLS

Such a variety of accidents are possible in the normal operation of the cable drilling tools, that many different fishing tools are necessary if the operator hopes to be equipped for any contingency that may develop. Perhaps the most common fishing job that arises with cable tools results from unscrewing of a tool joint in the well. If the joints are not "set up" securely, or if the threads are defective, vibration of the tools while in operation may easily cause one of them to unscrew. Furthermore, unless the driller is skilful in recognizing the difference in the cable vibration

after such an occurrence, the upper part of the string may be permitted to pound on the top of the detached portion until the ends become upset and the threads ruined. Breakage of various parts of the string of tools will result in all or a part of the string becoming detached—the drilling cable may pull out of the rope socket, the tool joints may "jump a pin" or break off as a result of unequal pressure on the bit, or excessive strain from other causes. Steel will crystallize as a result of the continued vibration and break at some weak cross-section, such as the base of a pin joint or across a wrench square. Defective welds often open and pull apart. The jars sometimes break so that the two links pull apart. If the casing shoe is held too far off bottom, the upper end of the string of tools may fall to one side and get caught under the shoe. A cave of loose material from the walls may bury the tools. Under-reamer lugs frequently break or become loosened and fall to the bottom of the hole. Any one of these occurrences will necessitate interruption in normal drilling procedure while the detached part is recovered or the condition remedied.

Use of Various Sockets.—A variety of types of sockets have been designed for taking hold of the different parts of the string of cable tools, some of which are illustrated in Fig. 128. The "slip socket," the "combination socket" and the "collar socket" will pass over the end and take hold of any cylindrical object. Frequently they are equipped at the lower end with a conical bowl which serves to guide the upright end of the detached tool into the slips. A group of other tools, among them the "horn socket," the "round spud" and the "corrugated socket," serve a somewhat similar purpose, but operate on a different principle. These tools are hollow and are driven down with the jars over the detached tool until a friction hold is taken. If the drilling cable has pulled out of the rope socket, a "tongue socket" may be used. This consists of a pair of slips on a mandrel which is lowered into the hole in the center of the rope socket. A "pin socket" may be used to engage the tapered threads of an exposed pin joint, if a tool joint has become unscrewed and the threads are not damaged. For taking hold of the jar reins when they pull apart in the well, several special forms of sockets equipped with slips in different positions are available; thus, there are "center jar sockets," intended to pass between and catch both reins of the broken jars; there are "jar rein sockets," designed to take hold when one broken rein is longer than the other; the "jar tongue socket" and the "slide jar socket," are tools that pass over and grip the tongue of the jars. Of these different forms of sockets, the combination socket, equipped with slips actuated by the pressure of a powerful spring, is of greatest utility and is most positive and reliable in action. However, the ordinary type of slip socket, in which the slips are placed on the ends of a U-shaped stirrup, is cheaper and, for many purposes, equally reliable.

Use of Rasps.—If the end of the detached tool has been upset and battered by pounding of the tools, it may be necessary to remove the ragged or upset edges or corners with the aid of a rasp. This is nothing more than a large file which is suspended on a drill stem and spudded up and down about the top of the detached tool. Two forms are available: one, the so-called side rasp, which is a single semi-circular bar, curved to the diameter of the tool on which it is to work, and the other a two-wing rasp, designed to pass over the end of the tool and work on two sides at once (see Fig. 129).

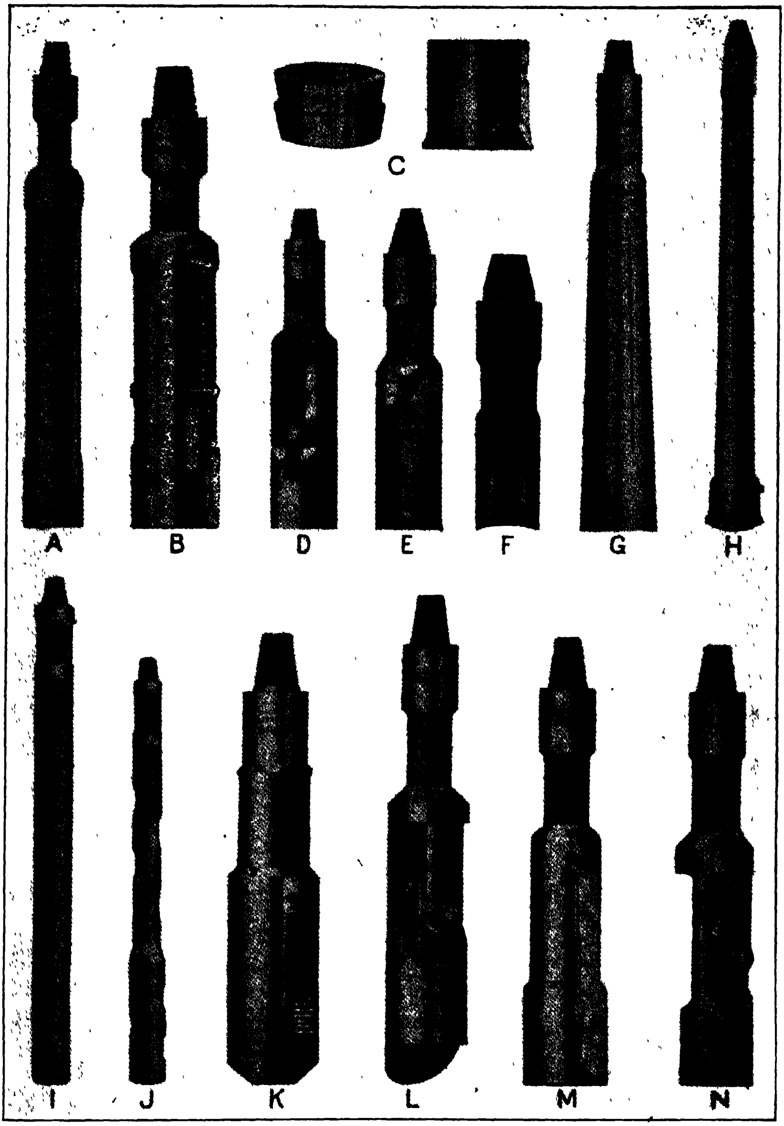


FIG. 128.—Types of sockets.

A, slip socket; *B*, combination socket; *C*, slips and bowl for combination socket; *D*, collar socket; *E*, rope socket tongue socket; *F*, bull dog pin socket; *G*, horn socket; *H*, horn socket with bowl; *I*, round spud; *J*, corrugated friction socket; *K*, center jar socket; *L*, jar rein socket; *M*, jar tongue socket; *N*, side jar socket.

Use of the Twist Drill and Twist Drill Spear.—When the detached object is so large or has been so badly upset that it fills the hole and prevents operation of a rasp or other fishing tool, a hole may be drilled vertically into it with a substantial twist drill which is rotated on tubing. After the hole is drilled, a twist drill spear may be lowered into it, a hold taken and, unless the friction is too great, the detached tool or object is withdrawn. The spear used in such a small hole is necessarily weak, and is not intended for lifting heavy objects, or for cases which require heavy pulling.

Use of the Wall Hook or Bit Hook.—If a drilling bit becomes detached from the rest of the string in the well, it often leans against one side of the hole so that the upper end is not accessible to fishing tools which must pass over it to operate successfully.

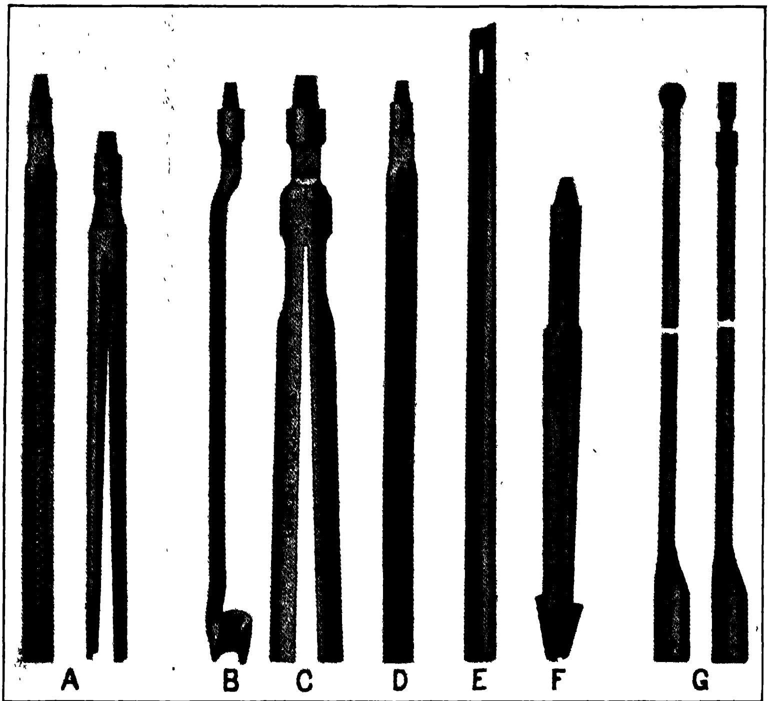


FIG. 129. Tools for recovering parts of the cable drilling "string."
A, types of rasps, *B*, wall hook, *C*, hollow-reamer, *D*, spud, *E*, whip stock, *F*, whip stock grab, *G*, types of jar knockers

For such a situation, the wall hook or bit hook is used. This is a tool (see Fig. 129) consisting of a long bar, offset from its point of support, with a semi-circular hook on the lower end, of proper size to slip around the tool under the collar, straightening it in the hole and supporting it while it is being withdrawn. It is equipped with a pin joint at the top, and can be lowered on a string of sucker rods or tubing, and functions when turned in the hole after reaching the proper depth.

Loosening Stuck Tools.—If the tools become fast in the hole as a result of caving of the walls, or by "heaving" of sand from the bottom, it is generally necessary to remove or loosen the material over and about them before they can be withdrawn. For this purpose, either a hollow reamer, a "spud," or a "whip stock" may be used (see Fig. 129). The hollow reamer is merely a cylindrical tube split into two wings and dressed to a sharpened edge at the bottom, which is spudded up and down on the tools

in the well. The two wings spring apart after passing the casing shoe, and the inner diameter is such that the reamer passes over the detached tools in the well and works on the material about them. The semi-cylindrical spud is used for a similar purpose. The whip stock is lowered on top of a lost string of tools when it is desired to drill by them. The beveled face of the whip stock causes the working tools to glance off to one side of the detached string. Tools may be sidetracked in this way, or they may be caused to fall into a hole drilled below them, in the hope that they will assume a more accessible position than they formerly occupied. The 'whip stock grab" is a fishing tool that is used in reaming the whip stock out of the well after the work is completed.

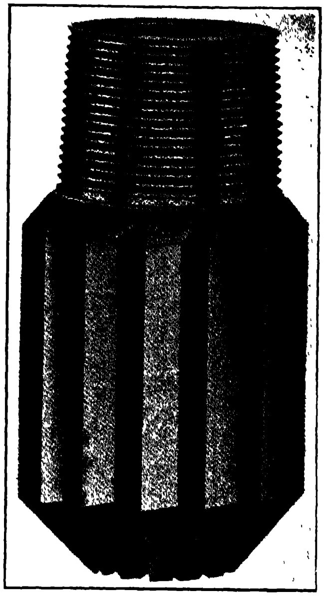


Fig. 130.—Hughes milling tool for cutting through and side-tracking casing

If the drilling tools are lowered without a pair of jars in the string, and become embedded in the hole, it may be impossible to release them by a direct pull on the drilling cable. In such a case a "jar knocker" (see Fig. 129) is often called into service. This is a heavy bar, from 8 to 24 ft. long, which is lowered into the well on the sand line with its lower end encircling the drilling cable. The drilling cable is put under tension and the jar knocker is repeatedly raised 20 or 30 ft. and dropped on the rope socket until the combined jar and pull releases the tools. The jar knocker may also be applied in releasing the links of the jars, if for any reason they should become locked while the tools are in the well.

Use of Milling Tools.—When a pin is broken from a tool in the well, it is occasionally necessary to cut a new pin on the broken end to aid in its removal. A milling tool designed for this purpose is lowered on 2-in. tubing and revolved until the new pin is formed. A milling wheel is attached to the tubing and revolved by a rope drive from the bull wheels. A part of the weight of the tubing is sustained by a special milling jack which permits of rotation of the tubing and close adjustment of the rate of feed. Milling tools of somewhat different design are also available for cutting through casing (see Fig. 130).

RECOVERING A DETACHED BAILER

While no very great strain is ordinarily placed upon the bailer or its supporting cable, the sand line, it will occasionally become fast in the hole so that it cannot be removed without breaking the sand line. Caving of the walls or heaving sand from the bottom may bury the bailer completely so that it cannot be withdrawn. Again, the sand line may break as a result of wear, or it may become unfastened from the bailer bail, or the bail may pull out from the top of the bailer. In such accidents one or another of the tools described in connection with casing fishing jobs or cable tool fishing jobs may be called upon, or a special tool called a "boot jack" or "latch jack" may be of service.

If the bailer cannot be pulled and the sand line is still intact and securely attached to it, a rope knife should be lowered and the line cut at the bail. The latch jack (see Fig. 131) may then be lowered on a fishing string with long-stroke jars, a stem and a rope socket, on the drilling cable.[3] The latch jack is a fork-shaped tool, often made from the upper half of an old set of jars, with a small bar or latch pivoted on a pin set in one of the two reins. As this instrument is lowered, the two reins

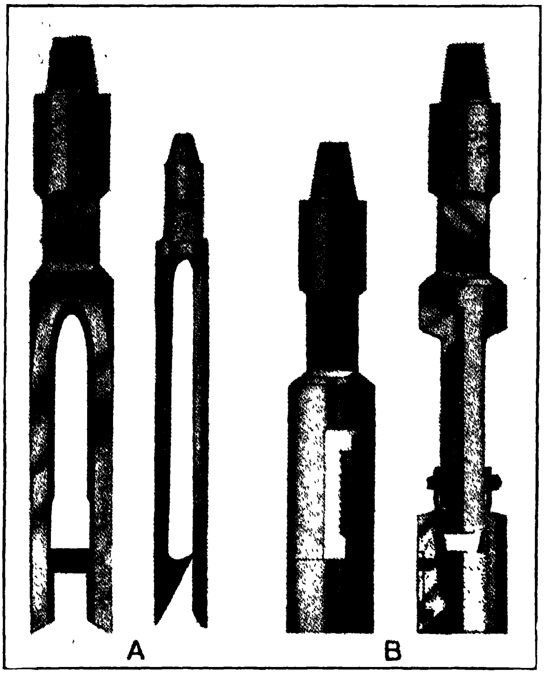


FIG. 131.—Fishing tools for recovering bailers. *A*, boot- or latch-jack; *B*, bailer grabs

pass, one on either side of the bailer bail, lifting up the latch on its pivot. When the bail passes the latch, the latter falls back into horizontal position and later engages the bail when drawn up. The tool is substantial enough to stand heavy pulling and the jars provide a powerful upward blow which soon loosens the bailer if the bail does not pull out. In the latter event, a casing spear or a bell socket may be called into service. A tool designed especially for recovering detached bailers is called a "bailer grab" (see Fig. 131). It contains one or two slips actuated by a powerful spring, and passes over the outside of the cylindrical portion of the bailer. If all of the methods suggested above fail, the bailer may be "drilled up" with the tools and sidetracked.

RECOVERING SMALL IRREGULARLY SHAPED OBJECTS

Recovering small irregularly shaped objects, such as under-reamer lugs, slips or parts of fishing tools that break in service, is accomplished with the aid of either an "alligator grab" or a "devil's pitchfork." The manner in which these tools operate will be apparent from an inspection of the illustrations given in Fig. 132.

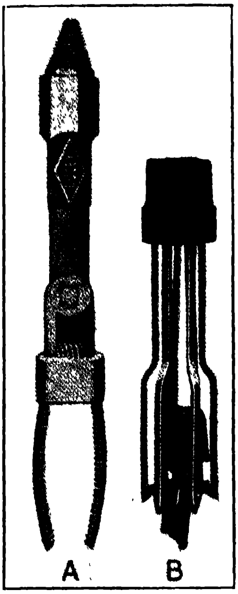


FIG. 132.—Fishing tools for recovering small irregularly shaped objects.
A, alligator grab; *B*, devil's pitch fork.

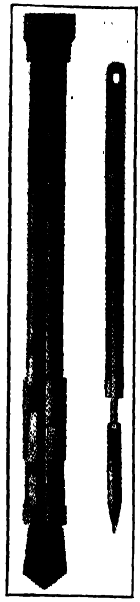


FIG. 133.—Wash-down spear with mandrel and jar.

Electromagnetic Fishing Tools.—Single-pole electromagnets have been devised and successfully used in recovering small or relatively light objects from a well, and efforts have also been made to use them in heavier service, in manipulating casing and withdrawing detached drilling tools.

For a variety of reasons, such tools have not been altogether successful or desirable from the operator's point of view. There is difficulty in designing an electromagnet sufficiently small in diameter to pass freely through the usual sizes of casing, and yet powerful enough to develop the lifting force or pulling force necessary to lift or free the lost tool. The magnetic force must be concentrated on the lower end of the magnet, which in many cases will have contact with the lost tool only over a very small surface area. Furthermore, unless the magnetism can be concentrated entirely on the end, it will tend to stick to the casing as it is withdrawn. Mud and sediment accumulating over

the detached tool will often prevent close contact between the metal surfaces. The difficulty of transmitting current into the well and protecting the conducting wires against abrasion, may be overcome by using a special cable for supporting the tool, with the transmission wires encased within its core; but such a cable would be expensive and probably not rugged enough for normal oil well service. In many cases where electric current is not available at the well, such a tool would be of no value. If the difficulties suggested above could be overcome by perfection of design, however, the use of electromagnetic force in fishing operations possesses interesting possibilities. Such a tool would be quicker and more universal in its application than other tools which depend upon accurately gaged slips, and which often fail to work because the detached tool is in an inaccessible position.

RECOVERING FRACTURED ROTARY DRILL STEM

The most frequent type of fishing job in rotary drilling is that occasioned by twisting off of the drill stem. Such a fracture usually occurs near the lower end of the stem as a result of torsional strain, resulting from the use of too great a pressure on the bit. The fracture may consist of a simple shearing of the pipe, or failure may occur at a tool joint. In some cases the "back lash" of the upper portion of the column of pipe, after the stem breaks, will cause a second fracture at some point above the first, so that the pipe is in three pieces in the well.

The overshot (see Fig. 117) is the favorite tool for recovering drill stem twisted off in this way; but if mud has settled about the stem, it may be necessary to use a "washdown" spear, which is a special form of trip casing spear equipped with a diamond-pointed bit on the lower end, and with openings through it for passage of the circulating fluid (see Fig. 133). It is lowered on a column of drill pipe of the same size as that detached in the well. The diamond bit, aided by the pump circulation, quickly forces its way through the accumulated mud and enters the broken stem until the slips take hold, after which the pipe can usually be withdrawn.

If the detached section of drill pipe cannot be pulled, the spear can sometimes be recovered by rotating the drill pipe on which it is lowered. Or if the fishing string has been tightly made up, some of the lost pipe may be unscrewed by "backing up" or turning the fishing string at the surface in the hope of unscrewing one of the tool joints in the detached column of pipe.

If the parted drill stem cannot be recovered with either the overshot or the washdown spear, it may be possible to unscrew a part of it in the well and remove it in sections. For this purpose, a string of pipe equipped with left-hand threads is made up, and a hold taken on the detached pipe, either with a spear or with a left-hand threaded pipe tap or die nipple. The fishing string is then rotated counterclockwise, which tightens the left-hand threads but unscrews the right-hand threads of the detached stem. There is more or less uncertainty as to just where the detached column will unscrew, but three or four joints of pipe can often be recovered with each run.

If the lost drill pipe cannot be recovered by either of the methods suggested above, a whip stock is lowered into the hole and the parted section is sidetracked. If the

upper end of the detached stem happens to be up inside of the well casing, a hole may be cut through the casing for the passage of the drilling bit and stem with the aid of a milling tool, after the whip stock is in position.

A means of attaching the drill collar and rotary bit to the drill stem in such a way that they are not detached from the stem if a twist-off occurs, near the lower end, is said to greatly reduce the number of rotary fishing jobs.[6] The Baughner device, named after the inventor, J. D. Baughner, a California well driller, ties the four bottom joints of drill stem, the drill collar and bit, to the nearest tool joint above. This is accomplished by means of a wire cable 80 ft. long, babbitted into a rope socket at each end, the sockets being shouldered and resting on the pin of the drill collar at the lower end, and at the upper end on the pin of the tool joint. Between the rope sockets and the pins, slotted washers are placed, which permit passage of the circulating fluid. The cable rotates with the stem, and in no way prevents circulation of the mud fluid. Should the drill collar or either of the lower joints break, the rope keeps them suspended so that they can be withdrawn with the upper part of the drill stem. On one well drilled in California, this device prevented 24 out of 27 fishing jobs due to twist-offs.

DETERMINING THE POSITION AND CONDITION OF A DETACHED TOOL IN THE WELL

Before selecting a fishing tool to recover a detached tool in the well, it is often essential to determine its position in the hole as well as the condition, form and exact size of the upper end. For this purpose, an "impression block" is prepared.[3] This consists of a round piece of wood about 2 ft. long, of such diameter that it can be readily lowered through the hole, and is concave at the lower end. A few nails projecting from the concave end serve to hold a mass of soft soap. The impression block is lowered into the hole, either on the bottom of the bailer or attached to the lower link of the jars by a pin joint cut on its upper end, until it rests upon the top of the detached tool. When withdrawn, the indentations in the soap indicate fairly well the position, form and size of the upper end of the tool in the well, and enable the driller to select a fishing tool to recover it.

It has been suggested that a special camera might be devised, with an electric lighting device and electric control, which could be lowered into the well and a photograph made of parted casing, a detached tool or any other obstruction. Such cameras have been used in photographing the position of magnetic needles in making surveys of diamond drill holes, but seem scarcely applicable under the conditions pertaining in oil well service. The well fluid and accumulated sediment would generally obscure the object even if a workable camera could be devised.

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CHAPTER IX

OIL FIELD HYDROLOGY; EXCLUSION OF WATER FROM OIL AND GAS WELLS

Occurrence of Water in Sedimentary Strata.—Everywhere, at a variable distance below the earth's surface, the rocks are supposed to be saturated with water. The upper surface of this body of ground water, called the "water table," is irregular in contour but roughly parallels the configuration of the earth's surface. In most regions it is found near the surface, but in arid regions it may be found at a depth of several hundred feet. Below the water table, the rocks are assumed to be saturated with water until a temperature is reached at which water cannot exist. This again, however, is a more or less indefinite depth and is conditioned by many irregularities. To the general assumptions just given, there might be cited numerous exceptions of mines the lower levels of which, far below the water table, are almost barren of water.

While all rocks below the water table are known to contain more or less water, the degree of saturation and the hydrostatic pressure are widely variable, and circulation of ground waters is confined largely to the more porous beds. Sandy strata, which offer relatively large pore space and freedom for the passage of fluids, are often completely saturated with water under high pressure, and are called "water sands," to distinguish them from rocks containing small quantities of low-pressure waters. It is probable, however, that even the so-called "dry sands" contain some water, and that they are only relatively dry. Clay, which is not usually thought of as a source of water, will often contain half again as much water as porous sand, but it does not yield its water so readily.

Many drillers believe that it is possible to distinguish between "water sands" and "dry sands" or "oil sands" by the texture or form of the sand grains. It is claimed that the grains of a water sand are sharper or more angular, or that they are smaller. Some believe that grains of mica are characteristic of water sand but are not ordinarily present in oil sand. While such characteristics are of value in correlating sands as between near-by wells, it must be recognized that the rock fluids are of secondary occurrence and cannot be in any sense related to the lithological properties of the sand, or to the minerals forming the grains. A water sand is any sand that contains water which it freely gives up. A sand which contains oil is an oil sand for present purposes, though at a former

period it may have been a water sand. Conversely, an oil sand, by exhaustion of its oil content, may later become water-logged.

Pressure within water-saturated sands will, in general, increase with depth below the water table, and is due in part to hydrostatic head of the superimposed column of fluid, and partly to rock pressure. There are many apparent exceptions to this statement, due largely to loss of pressure as a result of resistance offered by the minute rock openings. Waters in different beds, separated from each other by only a thin parting of impervious clay or shale, may be under quite different heads.

Much of the water present in the upper horizons of the earth's crust is replenished seasonally through outcropping porous beds, by percolating surface waters; and there is necessarily considerable lateral and vertical movement of these ground waters in adjusting the differences in pressure which naturally result. Much of the water present in rocks, however, particularly in the deeper sedimentary rocks, is connate water occluded within the rock mass during sedimentation. This water, too, may be forced to migrate by cementation, consolidation of sediments and the accumulating weight of overlying strata, but it is in many cases held practically trapped within the basins of folded structures.

Identification of Water Sands in Drilling.—In the usual processes of drilling, it is often a difficult matter to determine the pressure on a water sand, or the rate at which water may flow from it. In the standard or cable tool method of drilling, it is customary to maintain a certain depth of water in the hole, which may be sufficient to effectively prevent low-pressure water from entering the well. Thus, a 1,000-ft. column of water exerts a hydrostatic pressure of 434 lb. at the bottom of the well, and if the head on a water sand is less than this, no water will enter the well from it. On the other hand, if the differential pressure is sufficiently great, water may flow from the well into the sand. If the fluid level in the well sinks as a new sand is encountered, it is logged as a "dry" sand, but this usually means merely that it contains water under relatively low pressure. If, on the other hand, the fluid level rises when a new stratum is penetrated, it becomes evident that water is flowing into the well from the new sand, and that the fluid in it must be under greater pressure than that represented by the column of fluid in the well. A study of fluid levels during the process of drilling will thus give valuable data on possible sources of water which may prove troublesome during a later period. If it is safe to do so, the fluid in the well should be bailed down whenever a new sand is encountered until the nature and pressure of its fluid content can be determined. At such times, samples of the fluid should also be gathered for analysis and future comparison.

In rotary drilling, on account of the mudding of the walls and the necessity for continual circulation of fluid, it is a far more difficult problem to estimate the water-yielding capacity of the formations penetrated.

However, if a bed is porous and under low pressure, it will probably absorb fluid from the circulating system so that the fluid level of the mud pit falls and additional water has to be added. This should be accompanied by a decrease in pump pressure necessary to maintain circulation. If, on the other hand, a sand contains water under high pressure, the difference between its upward pressure and that of the column of circulating fluid may be so small that it is not shown by the pump gage and there may be nothing to warn the driller of the presence of a high-pressure water sand that may later cause trouble unless properly cased off. It is obviously impractical to bail down a rotary drilled well frequently in order to obtain samples of rock fluids, or to make tests of fluid pressure.

Relation of Water to the Oil.—Water sands may be found both above and below and occasionally within the oil zone, and are referred to respectively as "top water," "bottom water" and "intermediate water." The water which underlies the oil in the lower horizons of an oil stratum is commonly called "edge water." In horizontal or low-dipping strata, the lower portion of a thick oil stratum may contain water, the oil apparently floating on top of the water. It is probable, however, that in many supposed cases of this sort, there is an impervious bed separating the two, so thin, perhaps, that it has not been logged in the process of drilling.

Chemical Constitution of Ground Waters Associated with Oil Deposits.— In strata to which surface waters have access, the water is characteristically fresh, but in deeper horizons where movement is sluggish, the waters may acquire considerable percentages of dissolved solids from the surrounding rock masses. Connate waters occluded within marine sediments at the time of sedimentation were initially saline and in many cases have remained so throughout subsequent geologic ages. Such waters, by interaction of different dissolved salts, are often the cause of secondary cementation and replacement in porous rocks to which they have access.[5]

The universal association of brine with petroleum deposits is a matter of common knowledge, and some geologists believe that commercial deposits of oil are only to be found below the fresh water level. It is reasonable to suppose that great changes in the chemical constitution of these connate waters have occurred through diffusion and deposition of the dissolved salts: by supersaturation and chemical interaction on the one hand, and concentration of salts by solution from rock masses and evaporative effect of gases on the other. Oil field ground waters frequently contain several times as much dissolved solids as ordinary sea water. Change in temperature, as a result of migration of ground water, may alter its solution capacity for a given salt.

There are marked differences in the concentration of dissolved salts and in the nature of the salts present in oil field brines.[1] The waters of

different strata are usually distinctive, and often differ markedly from each other in chemical constitution and reactivity. The dissolved salts commonly present in ground waters are primarily the chlorides, sulphates, nitrates, carbonates and bicarbonates of the alkalies and alkaline earths (sodium, potassium, magnesium, calcium, barium and lithium). Iron, alumina and silica are often present in small amounts and occasionally hydrogen sulphide or sulphur dioxide will be found in solution. The preponderance of one or another of these elements or radicals is often a reliable characteristic of the water in a particular stratum, and the different strata in a given locality may in many cases be readily identified and correlated from well to well by making analyses of their contained waters and noting common characteristics. For example, a persistent sand overlying the oil measures in the Coalinga field of California contains dissolved hydrogen sulphide, and is so well known throughout the district by this characteristic that it is often used as a "marker" horizon in making correlations from one well to another.

In some fields the dissolved salts present in ground waters appear to bear a certain relationship to the proximity of petroleum.[6] It is found in many oil fields, for example, that the waters immediately associated with the oil measures are notably lacking in sulphates, but are often high in carbonates. There is some evidence to show that this may be attributed to the reducing effect of decomposing organic matter from which petroleum is formed; or it may result from slow reduction of the sulphates by prolonged contact of ground waters with petroleum itself, under certain conditions of pressure and temperature. Reduction of the sulphate to sulphide is accompanied by the formation of carbonate, and the proportion of carbonate is thus abnormally increased. An unstable sulphide of iron may also be formed as a result of this reaction, imparting to shales and clays a characteristic blue color.[6] The presence of barium and strontium may explain the absence of sulphates in some cases. In the Appalachian fields concentrated chloride waters associated with the oil and gas contain noteworthy amounts of calcium. The waters are characteristically lacking in sulphates, but usually, also, lack carbonates. In some of the San Joaquin Valley fields of California, the surface waters contain sulphates, but in the sands immediately above the oil zone, sulphates practically disappear and are replaced by carbonates. Edge waters and bottom waters in this region are high in chlorides. So persistent are these characteristics that in certain fields operators find it advantageous to make chemical analyses of all waters encountered in the drilling of wells, and are able to predict, in some measure, the position and proximity of the source of the sample with respect to the oil zone.*

* Suitable methods for determining quantitatively the chemical characteristics of dissolved salts in ground waters may be found in a reference manual published by

It is a matter of common belief that petroleums suffer an increase in density by contact with ground waters. This may be explained from the chemical point of view as a result of the reduction of dissolved sulphates in the water in contact with the oil. As a product of this reaction, hydrogen sulphide is formed, and the carbon formerly linked with this hydrogen forms carbon dioxide or carbonate. It is a well-established fact that oil in contact with sulphides will increase its density and viscosity by the formation of complex hydrocarbon-sulphur compounds.*

Temperature undoubtedly plays an important rôle in influencing the solution capacity of ground waters for soluble salts. Temperature increases in a constant ratio with depth, and temperatures ranging between 100 and 140°F. are not uncommon in oil field ground waters produced from a depth of 3,000 or 4,000 ft. Waters which become saturated with a soluble salt at such temperatures may, on subsequent cooling, precipitate cementing material between the grains of porous rocks to which they have access. Chemical interaction between dissolved salts as a result of contact between different ground waters will have a similar effect. It is thought that the accumulation of large quantities of salt from waters in oil and gas wells, and the sealing of the pores of productive oil and gas sands by deposition of salt, also result from such reactions, though in some cases it is probably due to the evaporative effect of natural gas on water within the well, evaporation of the water causing accumulation and eventual saturation of the well fluid accompanied by deposition of salt.

Effects of Water Incursion in Oil Sands.—Accumulated water in the well has a marked influence on the rate at which oil may enter from an oil sand in the bottom. Oil flows into a well by virtue of the gas or hydrostatic pressure operative upon it. If the oil or gas pressure is opposed by the hydrostatic pressure of water accumulated within the well, it is obvious that less oil will enter. Frequently the water pressure will be so great that no oil enters, and occasionally the direction of flow may be reversed, water entering the oil sand from the well.

If water enters an oil-producing stratum from a well penetrating it, the oil will be forced away from the vicinity of the well. Furthermore,

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the American Public Health Association, entitled "Standard Methods of Water Analysis." The reactive properties of ground waters can best be studied by converting the results obtained by quantitative analysis to a character formula expressed in primary and secondary salinity and alkalinity as proposed by C. Palmer in Bulletin 479, U. S. Geological Survey, entitled "The Geochemical Interpretation of Water Analyses." U. S. Bureau of Mines Bulletin 195, entitled "Underground Conditions in Oil Fields," by A. W. Ambrose, also describes the Palmer method of interpretation.

* Rogers, G. S., Relation of sulphur to variation in the gravity of California petroleum, *Trans.*, Am. Inst. Mining & Met. Engrs., vol. 57, pp. 989–1009, 1917.

water entering an oil sand in this way apparently has the effect of altering the properties of the sand so that it does not yield readily to the passage of oil through it, even if at some later time water is excluded from the well. If large volumes of water are permitted to enter, they may migrate through the oil sands, influencing the production of wells at a considerable distance from the point at which they enter. Large areas may thus become flooded to such an extent that profitable production of oil from them becomes impossible.[8]

Aside from its influence on oil production, the presence of water in the oil produced by a well increases the cost of operating the well, often necessitating the pumping of large volumes of worthless fluid, which must be separated from the oil at additional expense after it reaches the surface. Water-oil mixtures in the well sometimes form emulsions from which the oil may only be extracted with great difficulty and expense.

Because of the difficulties that result from the presence of water in oil wells, it should be excluded by suitable means. The necessity for water exclusion is one that is well recognized by oil producers, and the methods involved in accomplishing it have received a great deal of attention, particularly in certain fields where the menace of water incursion has become a problem of vital importance.

METHODS OF EXCLUDING WATER FROM WELLS

It has been shown that water entering an oil well may have its source in water sands located either above or below the oil zone, and that in some cases it may originate within the oil sands themselves as edge water; or it may be present as an "intermediate water" between two oil sands. The eventual encroachment of edge water into a well is unavoidable, and by present methods it is impracticable to exclude intermediate water if we would produce from two or more oil strata simultaneously; but the exclusion of extraneous top and bottom waters is readily accomplished by any of several methods. In the case of bottom water, in wells drilled to too great a depth, exclusion methods involve the placing of plugs which effectively seal off the lower portion of the well below the productive zone; while in the exclusion of top water, it is necessary to seal off the space below the source of the water, between the walls of the well and a watertight casing. Plugging off bottom water is relatively simple, but the effective and permanent exclusion of top water offers a problem that has taxed the ingenuity of oil producers to the utmost. Most of the flooding of oil sands that has resulted in many of our older fields has been due to ineffective methods of top water exclusion.

Exclusion of Top Waters

Use of Packers.—Early methods of excluding top water involved the use of various forms of packers between the casing and the walls of the

well. Bags of dry seeds or cereals were sometimes lowered into the well and manipulated until they passed under the casing shoe and up behind the casing above the shoe. On contact with water these materials expand and close the space about the pipe so that the descent of the water is checked. Packers made of loosely wrapped canvas or hemp rope, placed on the outside of the pipe before lowering into the well, may be

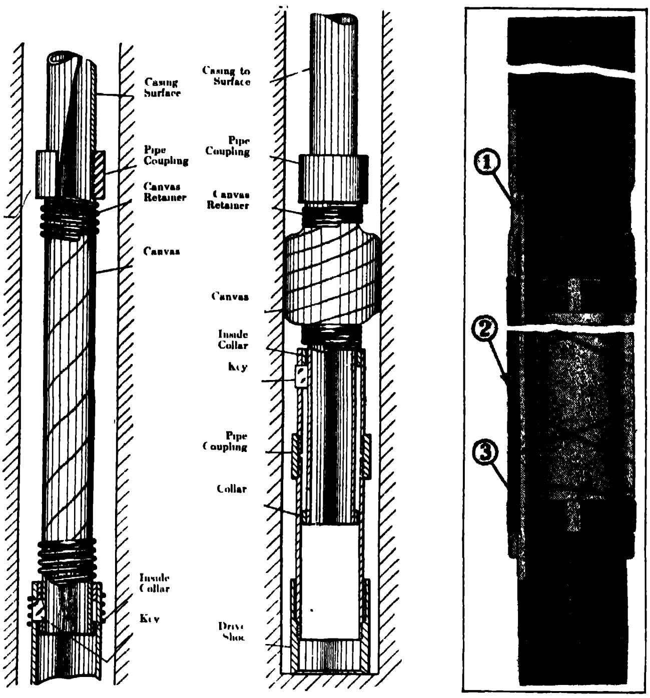


FIG. 134.—Types of canvas packers.

Lucey canvas packer, (a) before setting, (b) after setting, (c) Layne & Bowler canvas packer with lead cone, (1) threaded sleeve for setting, (2) canvas and (3) lead cone.

compressed into a shorter length, causing increase in diameter by proper manipulation of the pipe (see Fig. 134). Mechanical packers, designed to expand a rubber cylinder against the walls of the well by rotating the casing on which they are placed, are available, and may be effectively used in excluding water under favorable conditions.* All packers are constructed of materials which can scarcely be regarded as permanent in the sense that they will function effectively throughout the life of the well, and permanent water exclusion is necessary inasmuch as continued oil production is contingent upon it. Ordinarily, it will not be possible to replace the packer at such times as it may cease to be effective, since

* JEFFERY, W. H., "Deep Well Drilling." Published by W. H. Jeffery Co., Toledo, Ohio, 1921. See particularly pp. 291-300.

it is usually difficult to withdraw the casings from a well after the walls have had time to settle about them. Because of the temporary nature of packers and the difficulty and uncertainty of setting them properly, they are seldom used for permanent exclusion of top water.

Mechanical packers are widely used for water exclusion in the older oil fields of the eastern United States, where the wells are of small capacity and relatively shallow, and where the water problem is not a matter of

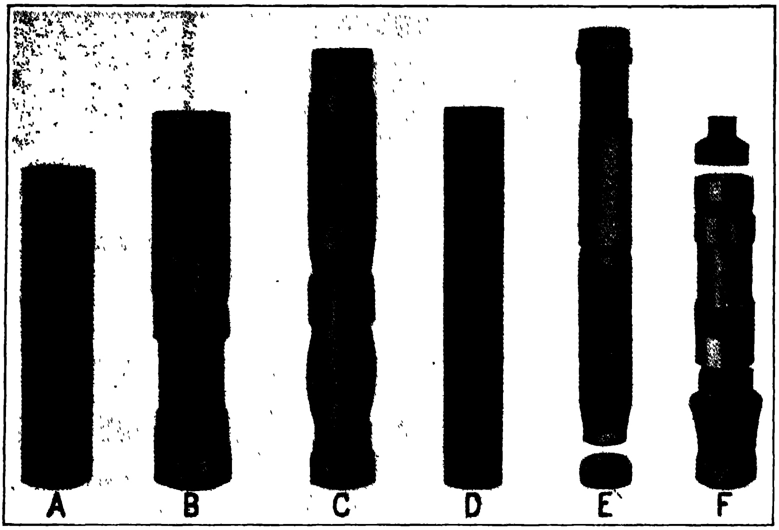


FIG. 135.—Types of packers.

A, bottom hole packer; *B*, disc wall packer; *C*, hook wall packer; *D*, anchor packer; *E*, Robinson screw-down packer; *F*, cave packer.

such vital importance as in many of the western fields. A variety of different types of packers are available, designed for use under different conditions. All mechanical packers operate by expanding a hollow cylinder of rubber, lead, canvas or burlap at the desired point in the well, either by compression from the ends, against a tapered metal sleeve or by rotation of screw devices. They are lowered and manipulated on either casing or tubing, and may be used to seal off the space between two strings of pipe, or between the pipe and the walls of the well. Rubber packers range from 3 to 8 ft. in length, the rubber sleeve varying from 1 to 3 ft. in length. Canvas packers are commonly about 8 ft. long, with a canvas or burlap sleeve 3 ft. in length, though special packers of this type may be secured which are as long as 20 ft., with an 8-ft. sleeve of canvas or burlap.

Bottom-hole packers (see Fig. 135) are used on the lower end of a string of pipe to close the space between the pipe and the walls of the well. The packer is held in its extended position by copper rivets through the conical metal sleeves, but these are sheared, permitting the sleeves to telescope and expand the rubber cylinder

when the full weight of the pipe is allowed to rest on bottom. The lower end of such a packer is equipped with a substantial reinforcing shoe, while the upper sleeve is threaded to connect with the casing. The rubber cylinder fits snugly over the top or inside sleeve, and is about 3/8 in. smaller in diameter than the hole it is designed to close when expanded.

Wall packers are used to close the space between two strings of pipe, or between the pipe and the walls of the well at some point above bottom. They are of several forms, the better known types being the disc wall packer, the hook wall packer, the anchor packer and various forms of screw packers. Wall packers are often equipped with a series of slips operating on a tapered cone, and friction springs which are intended to support the weight of the casing or tubing on which the packer is placed. Screw connections are provided at top and bottom for tubing or casing.

The disc wall packer (see Fig. 135) is lowered to the desired position, coupled into the column of casing at the proper point. The slips are held on the lower portion of the conical sleeve by a hinged steel disc, across the inner opening of the hollow sleeve composing the body of the packer. A weight—such as a piece of 1-in. pipe, 6 or 8 in. long, dropped from the surface when the packer is in position—breaks or dislodges the disc and releases a spring surrounding the lower sleeve and compressed between the slips and the bottom collar. This spring forces the slips upward on the tapered cone. Further lowering of the column of pipe causes the friction springs to advance the slips further up the conical sleeve, pressing them outward until they bear against the walls of the well or against the outer casing. The slips thus support the casing or tubing and the weight of the pipe above the packer, compressing the rubber cylinder, causes it to expand until it fills the space about the pipe.

The hook wall packer operates in a similar manner, except that the slips are held on the lower part of the conical sleeve by a hook latch, which is released by turning the casing or tubing through 180 deg. (see Fig. 135). This packer is lowered into the well on the tubing or casing, with the hook latched. When about a foot above the point where the packer is to take hold, the pipe is given a half turn to the right, thus disengaging the hook and releasing the slips. The friction springs prevent the slips and hook from turning with the pipe. After the hook is disengaged, the pipe is lowered until the slips slide up the tapered sleeve and engage the walls. This form of packer can be released by raising the casing and turning to the left until the hook is re-engaged, after which it can be set at a lower position if desired. The packer can be readily withdrawn from the well without re-engaging the hook.

Anchor Packers.—Disc and wall packers are used on casing or tubing which does not rest on the bottom of the well. If the pipe rests on the bottom of the hole, an anchor packer may be used at any desired point in the column of pipe. This type of packer is similar to the bottom hole packer described above, except that the latter is equipped with a shoe on the lower end while the anchor packer has a pipe connection. It is frequently used to close the space between the two strings of pipe, or between the casing and the walls of the well, placing the proper length of casing below the packer to bring it to the desired depth in the well when the string of pipe rests on bottom. Another form, known as the "disc anchor packer," cannot be released until a hinged disc is broken by a blow with the bailer or drilling tools, or by dropping a weight upon it from the surface.

In another form of anchor packer, the two sleeves are fastened together with a coarse square thread (see Fig. 135). The metal above the thread is turned down, so that by screwing the upper sleeve down until the threads no longer engage, the two sleeves telescope freely under the influence of the superimposed weight of the pipe, bringing pressure to bear upon the ends of the rubber cylinder. This form of packer may be conveniently used on the same string of casing with a bottom packer, as, for example, when a wall packer is to be set above a water sand, and a bottom packer on

a shoulder of rock below. The bottom packer is set in the manner described above; then, by taking a light strain on the casing and turning the pipe two full turns to the right at the surface, the top packer is released from the threads and seated against its rubber cylinder. Release of tension on the pipe then expands the rubber against the walls.

Screw Packers.—The packers thus far described accomplish the expansion of the packing material merely by the superimposed weight of the casing. Another type of packer is designed to operate without the aid of the weight of the casing, and

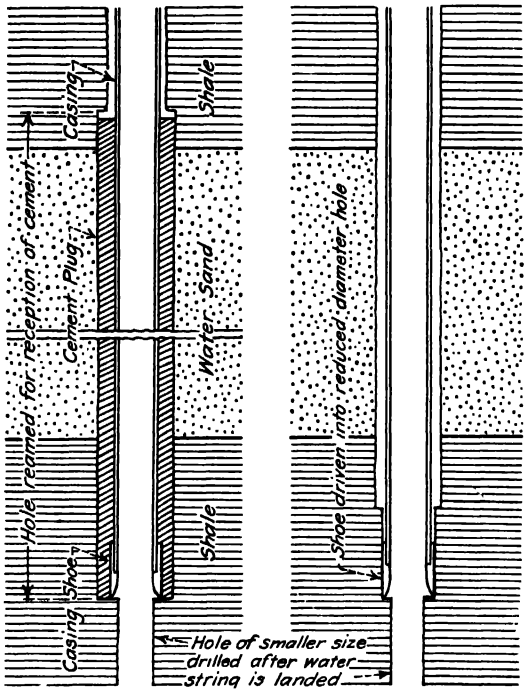


FIG. 136.—Ideal form of cement water shut-off. FIG. 137.—Formation shut-off.

without the necessity of an anchor extending down to the bottom of the hole. This is the screw-down liner packer, which expands the packing material by screwing the upper of two conical metal sleeves into the lower. This packer is lowered into the well and set by means of a special "letting-in tool" mounted on a column of tubing (see Fig. 135). With this type of packer it is possible to lower a short column of casing with a packer at each end, and to set both packers firmly against the walls in such a way as to exclude the water or a caving formation, though the casing does not extend either to the bottom of the hole or to the surface. Such a packer is useful for excluding water or caving material at shallow depths where the weight of the superimposed casing or tubing may be insufficient to properly expand a wall packer of the ordinary type.

Since a packer forms a permanent part of the well equipment, it must be constructed of material that will be long lived, and must not obstruct the free passage of tools or other well equipment through it. In some instances, packers must be

gas-tight, a feature which is accomplished by a special rubber seal between the telescoping metal parts. Packers equipped with rubber cylinders are best adapted for use in hard rocks that do not crumble under the side pressures developed. For use in loosely cemented, unconsolidated formations, such packers are little used, the canvas packer being generally preferred.

Formation Shut-offs.—For many years prior to the development of cementing methods, it was customary in the fields of the western United States to exclude water from oil wells by what is called the "formation shut-off." In excluding water by this method, it is first necessary to reach a bed of some substantial, impervious material, such as hard shale or "shell," in which to accomplish the shut-off. When the casing has been properly "landed" on such a stratum, a hole slightly smaller than the casing is drilled for a few feet below the shoe, and the casing is driven into the pocket thus prepared (see Fig. 137). The frictional pressure about the lower end of the casing thus developed, usually aided by accumulation of clay and detritus from the sludge in the well, is often sufficient to seal off overlying waters effectively. This method of water exclusion, however, is not always successful; and even though it may apparently be so at the time it is made, in a later period, when water has had time to accumulate back of the casing, it may and often does become ineffective.

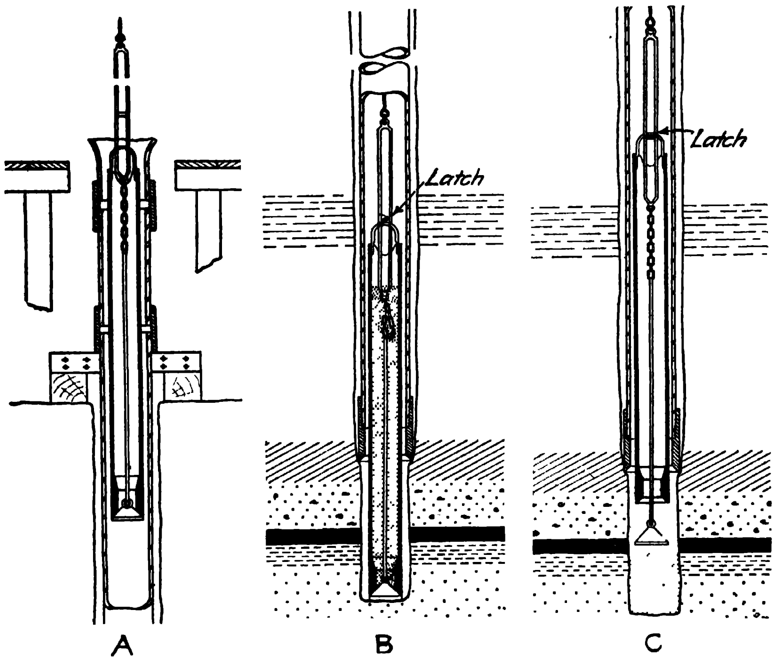
Cementing Casing

The most effective methods yet devised for the exclusion of top waters make use of cement, which is forced in a fluid condition into the annular space between the walls of the well and the casing, and allowed to set and harden, forming a permanent and impervious barrier to the downward movement of top water (see Fig. 136). Portland cement mixed "neat" (*i.e.*, without sand), in from 50 to 60 per cent of water, is commonly employed, though sometimes the walls of the well are given a preliminary wash with a thin mixture of hydraulic lime.

A variety of different methods have been developed for accomplishing the insertion of the cement into the well.[21] In an early method, the liquid cement is lowered in specially constructed bailers which dump on reaching bottom. Later methods made use of auxiliary tubing through which the cement was pumped to the bottom of the well. In still more modern methods, widely employed at the present time, the cement is pumped directly into the well casing.

Bailer Method of Cementing.—For lowering cement into a well, special forms of bailers are employed, the one illustrated in Fig. 138 being typical. Another form, closed at the lower end with a glass disc, is illustrated in Fig. 139. The glass is broken by a metal plunger on reaching bottom.

The cement is mixed in a wooden or metal box placed at a slight elevation above the derrick floor, and flows through an inclined trough leading directly to the well.[15] A lip on this trough serves to guide the cement into the bailer, which is suspended in the well with the top immediately below the discharge end of the trough. The bailer must make several trips to the bottom of the well, inasmuch as 2 or 3 tons of cement will ordinarily be necessary. When all the cement has been



(*After Swigart and Beecher in U. S. B. Mines Bull.* 232).

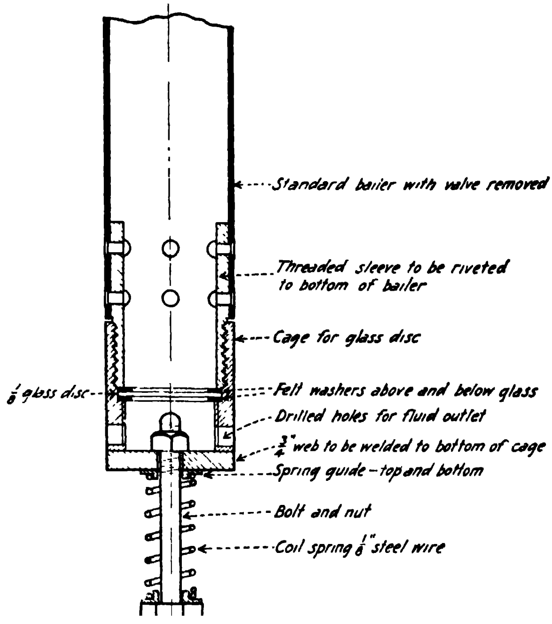
FIG. 138.—Illustrating operation of latch-jack dump bailer.

A, bailer entering well, lower end closed. *B*, bailer at bottom of well, ready to dump; *C*, after dumping, valve held open by latch.

deposited on bottom, the casing is raised until the shoe is above the cement level, and is filled with water. The upper end of the casing is then plugged and the column lowered to bottom. The water within the casing, being unable to escape, prevents the cement from entering the lower end of the pipe as it is lowered, thus forcing the cement to assume its desired position about the lower end of the casing. After the pipe has been lowered to bottom, it should be driven ahead for a few feet, to prevent the cement from finding its way under the shoe before the initial set occurs.

Instead of filling the casing and well with water, which may be tedious or difficult of accomplishment if the formation tends to absorb water, a

cementing plug may be used. Cementing plugs for this purpose may be had in several forms, the Baker and Hall plugs illustrated in Fig. 140 being well-known types. After the cement has been placed, the plug may be lowered attached to the dart of the bailer, until it is within a



(*After H. B. Thompson, California State Mining Bureau, Dept. of Oil and Gas*).
FIG. 139.—Glass-bottom dump bailer.

few feet of the casing shoe, when, on raising the bailer, the plug will become wedged in the pipe. A quick jerk breaks the eye bolt which connects the bailer and plug, so that the bailer can be withdrawn, leaving the plug wedged in the lower end of the casing. The plug effectively

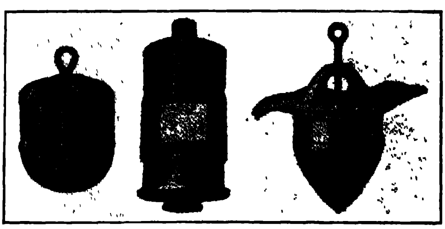
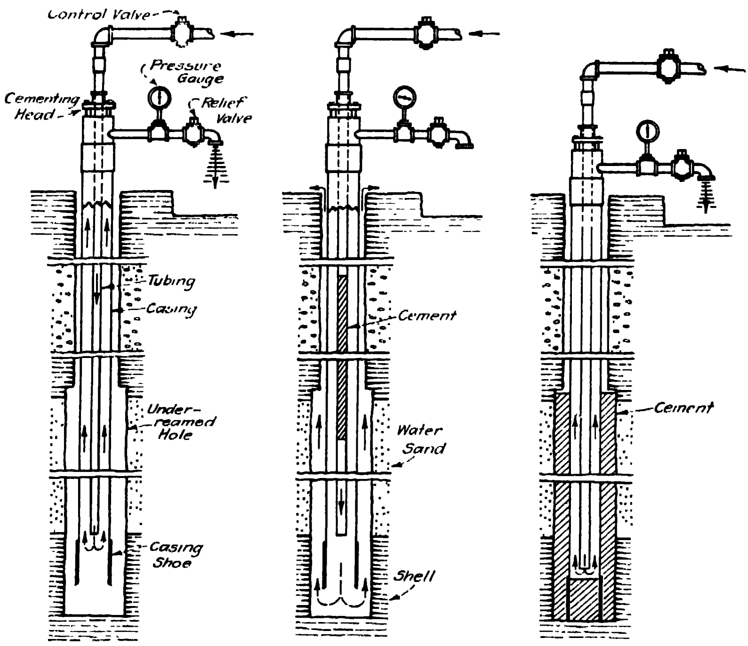


FIG. 140.—Types of cementing plugs.
Left, Hall plug; center, Baker "sure-shot" plug for use with dump-bailer method of cementing; Right, Baker cement retainer for use with tubing method of cementing.

closes the casing so that when it is lowered into the liquid cement the latter is forced up to its desired position about the pipe. The plug is built of brittle cast iron, and may be readily broken up with the drilling

tools, together with the small amount of cement which may find its way into the casing below and about the plug, when drilling is resumed.

Tubing Methods.—Placing cement in the well by one or another of the tubing methods requires the use of a pump and a column of 2- or 3-in. tubing extending down from the surface, inside of the casing, to within a few feet of the bottom. In order to prevent the cement, which is pumped down through the tubing, from accumulating within instead of outside of the casing, a packing device filling the annular space between the tubing and casing is provided, either at the lower end of the casing ("bottom packer method") or at the casing head ("top packer method")



(*After F. B. Tough in U. S. B. Mines Bull* 163)

FIG. 141.—Three stages in the tubing method of introducing cement.

(*a*) circulation established through tubing and casing; (*b*) cement passing down through tubing, circulation under shoe of casing; (*c*) cement in place, circulation again through casing, casing lowered to bottom.

(see Fig. 141). In either case, but especially in the latter, the casing should be filled with water.

For use as a packer on the lower end of the tubing, a disc or bushing screwed to the tubing by a left-hand thread may be used. The outer diameter of the disc is such that it fits snugly inside of the casing, but there must be sufficient clearance to assure its free passage as the tubing is lowered. Other more elaborate types of packers may be used on the lower end of the tubing, such as the Graham packer, illustrated in Fig. 142. If the packer is to be placed at the top of the column of casing

instead of at the bottom, any form of stuffing box casing head may be used (see Fig. 143), and if cement is to be prevented from entering the lower end of the casing, the well must be filled with water.

Since the cement must be forced under the shoe and up behind the casing, it is necessary that circulation down through the casing or tubing and up to the surface be established before the cement is inserted. Assuming that it has been possible to secure circulation by applying pump pressure, the tubing and packer are placed in position with the casing shoe a few feet off bottom; pump connections are provided and arrangements made for mixing the cement.

After the cement has been pumped into the tubing, the pump suction is switched to a supply of water, which serves to cleanse the pump and tubing of cement and force the latter to the bottom of the well. On emerging from the lower end of the tubing near the casing shoe, the cement is unable to enter the space within the casing and is forced out under the shoe, accumulating in the annular space between the casing and the walls of the well.

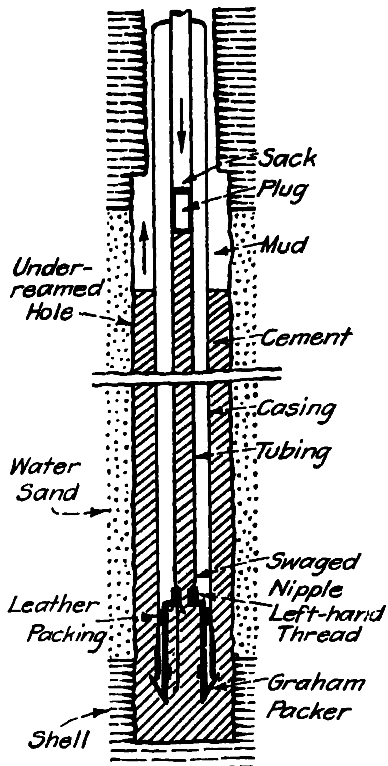
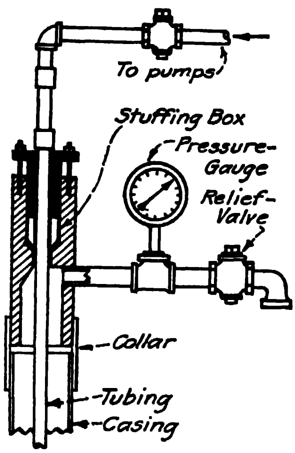


FIG. 142.—Tubing method of cementing wells using bottom packer.

It is important to stop pumping when the cement is all out of the tubing, otherwise it will be forced too high above the shoe and will become much diluted with water. The time to stop pumping may be determined by calculating the volumetric capacity of the tubing, and keeping account of the volume of water pumped down on top of the cement. This may be done either by pumping the water from a gaging tank, or through a water meter; or it may be done approximately by counting the strokes of the pump, if the capacity per stroke is known. In a somewhat more positive method, a restriction (such as a swaged nipple) is placed on the bottom of the tubing, and a small wooden plug is pumped down through the tubing ahead of the water which follows the cement. When the plug reaches the restriction in the end of the tubing, it is unable to pass, the pump pressure suddenly increases, and the operator knows that all cement is out of the tubing (see Fig. 142).

After the cement has reached its proper position outside of the casing, the latter is given a few turns to distribute the cement about it, and then lowered until the shoe rests on bottom. A little cement will generally find its way into the casing as this is done, and if the top packer method has been used, the surplus cement can then be flushed back to the surface through the casing, by pumping more water down through the



(*After F. B. Tough in U. S B. Mines Bull* 163)
FIG. 143.—Arrangements at casing head for cementing under pressure by tubing method.

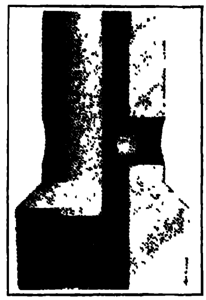


FIG. 144.—Cementing head.

tubing. In any case, the tubing and packer must be raised above possible contact with any cement which may have found its way inside of the casing before the cement has taken its initial set. On withdrawing the tubing, the casing should be left filled with water in order to prevent cement from finding its way back into the casing through any channel which might be left under the shoe in case the latter does not rest squarely on bottom. Hydrostatic head should be maintained within the casing until the cement has properly set. Some operators consider it good practice to hold a pump pressure of 50 lb. within the casing during the setting period as an added precaution. Cement left within the casing must be drilled out when drilling is resumed, an operation which may split or otherwise damage the casing; or it may so jar the pipe and the surrounding cement plug that the latter is loosened from the pipe or the walls of the well, or is so badly fractured that it is no longer watertight.

Methods of Placing Cement by Pumping Directly through Casing.—Development of the tubing methods described above led eventually to the pumping of cement directly into the casing. Two widely used cementing methods of this type are the so-called "Perkins process" and the "Scott process."

The Perkins process for cementing casing utilizes a pair of wooden plugs to separate the cement from the well fluid during its passage through the casing.[21] The plugs also provide a means of indicating to the operator when the cement has reached its proper place behind the casing. The plugs used are of various forms, those illustrated in Fig. 145 are typical. The lower plug goes into the well first, between the cement and the well fluid. The upper plug follows the cement into the well and prevents it from becoming diluted with the water used to pump the cement down. The plugs are carefully turned to a diameter slightly smaller than the casing through which they pass, and are equipped with wooden or metal and rubber washers which fit snugly within the casing. The lower plug is turned to a bottle-neck form below its flexible rubber washer and the casing shoe is held at such a distance off bottom that when the lower end of the lower plug passes through and rests on the bottom of the well, the upper end still projects within the casing (see Fig. 146). The washer, being flexible, yields to the pump pressure, and the free space left by the bottle-neck form of the plug permits the cement to flow out into the well. Continued pumping will eventually force all of the cement out of the casing and the upper plug will come to rest on the lower. The washers on the upper plug are stiff, and do not yield to the pump pressure; hence, as soon as it is stopped by the lower plug, circulation is cut off. Pump pressure at once increases and the operator knows that all cement is out of the casing. The latter is then lowered until the shoe rests on bottom, enclosing both plugs within it, and the casing is driven into the bottom for a few feet to close all possible channels through which the cement might find its way back into the casing. Pressure should be held on the well until the cement takes its initial set. Fig. 146 illustrates three stages in the process of introducing cement into a well by this method. Fig. 145 illustrates a somewhat better plan which makes use of an annular disc of cast iron to retain both plugs within the casing. The lower plug is in this case bored with holes which pass the well fluid after the plug comes to rest on the disc. A back-pressure valve prevents cement from flowing back into the casing.

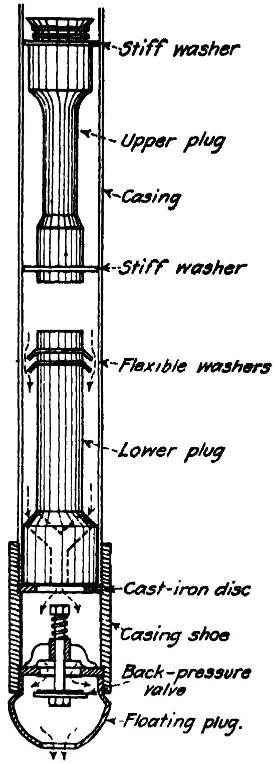


FIG. 145.—Perkins cementing plugs used in connection with floating plug and back-pressure valve.

Pumping Cement Directly into Casing without Barriers.—A rather widely used process in the California fields is one which is similar to the Perkins process described above, but operated without plugs or barriers of any sort to separate the cement from the well fluid. Two factors involved in this method tend to make the results somewhat uncertain: first, the extent to which the cement may become diluted by admixture with the well fluid and water used in pumping; and second, the uncertainty concerning the precise time at which the last of the cement passes out of the casing. Extensive use of the method has shown that admixture with the well fluid is not ordinarily detrimental in casings under 10 in. in diameter. The time of passage of the cement through the casing can be calculated with fair accuracy by measuring the water used in pumping it down, using an amount equivalent in volume to that of the casing. The water so used may be gaged from a tank or through a meter. Most operators prefer to stop the pump while a little cement is still left in the pipe in order to avoid possible dilution of the cement above the shoe, though the necessity for this is doubtful, since the greater density of the cement would probably cause it to sink to the bottom after flow of fluid from the casing ceases.

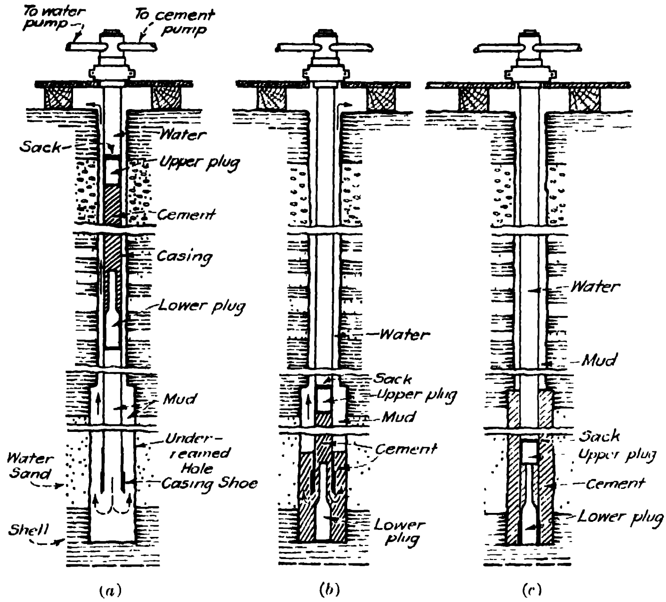
Plugging Wells with Cement

If a well has been drilled through a productive oil sand and has encountered bottom water, or if the lower portion of the productive zone is partially flooded with edge water, it will be necessary to seal off the water by plugging the lower part of the well. Occasionally bottom water will find access to the well through cavities and crevices resulting from the use of explosives to stimulate oil production. The plugging of a well that has been drilled too deep is readily accomplished by either of the cementing methods that have been described above, but for most bottom water jobs the bailer or tubing methods are employed.[19]

It will be important in such work to estimate carefully the volume of that part of the well which it is desired to plug off, and to use the proper amount of cement to accomplish it. Too much cement might result in sealing a portion of the overlying productive oil sands. The casing and tubing must, of course, be withdrawn to a point above the level of the cement, otherwise it will be impossible to withdraw them in case of necessity at some future time.

Another method that has proved effective in cementing off bottom water is that developed by W. W. McDonald for use in the Illinois fields. In this process, a hydrostatic head is maintained in the well sufficient to cause movement of water into the sand to be cemented. Tubing is then lowered to a point from 2 to 4 ft. above the top of the sand to be cemented. Dry cement in small amounts is then fed into the upper end of the tubing

and washed down with water. This cement is carried into the water sand by the movement of water from the well, and gradually seals the pores, simultaneously building up a cement plug within the well to the height of the lower end of the tubing. It is important in this process to have a means of measuring the fluid level within the well as the work is in progress.



(*After F. B. Tough in U. S. B. Mines Bull.* 163).

FIG. 146. Three stages in the Perkins process.

(*a*) plugs and cement in process of being pumped through casing: water is pumped down on top of the upper plug, the well being filled with fluid, (*b*) the lower plug and some of the cement has reached the bottom of the well, upper plug still descending, (*c*) upper plug rests on lower plug, cement is in place and casing has been lowered to bottom

If a bottom water sand is under high pressure, the upward force of water may make it impossible to hold the liquid cement in the bottom of the well until it sets and hardens. Or perhaps water flowing up through the cement will so agitate and dilute it that it does not set properly; or channels may be developed through or about the cement plug which render it ineffective. In such case it is necessary to bridge or plug the bottom with some solid material, to provide a support for the cement and to protect it from the ascending waters until it can attain its initial set. Bundles of strands from annealed wire cables, cut into short lengths, with hemp or manila fiber unraveled from old rope, can be rammed into a compact mass in the bottom of a well with the drilling tools, to control flowing water partially and to serve as a foundation for a cement plug.[21] Short hook-shaped pieces of annealed wire cable strands also serve as an admirable reinforcing material for a cement plug when added strength is

necessary. Lead wool placed in the well in small bundles has also been used effectively in plugging off bottom water, and in preparing a foundation for a cement plug. Various forms of wooden, lead or cast-iron plugs are also available for this purpose (see Fig. 147). It may be necessary to provide a plug which will resist an upward pressure of 1,000 lb. or more per square inch in cases where a strong flow of high-pressure water is encountered. In such instances it is a good plan to drill entirely through the bottom water sand, starting the plug in a lower stratum where it may obtain a formation lock that will better resist the heavy upward pressure. Mudding under high pressure, as described on page 295, is also effective in temporarily controlling the flow until a cement plug can be placed.

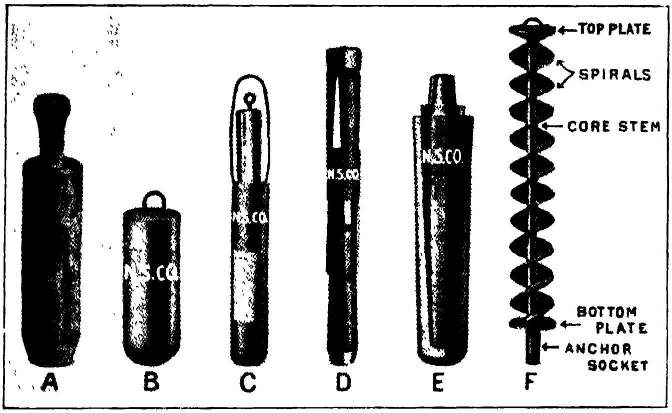


FIG. 147.—Types of plugs.

A, common wooden plug; *B*, lead plug; *C*, lead and rubber plug with mandrel; *D*, limit plug; *E*, wood and rubber plug; *F*, Guiberson-Crowell bottom water plug

The Guiberson-Crowell plug is a useful device for plugging off bottom water. It consists of a pair of heavy spiral springs wrapped about a metal stem and maintained under tension, as indicated in Fig. 147, by a wooden dowel pin driven through the stem. Oakum saturated with melted pitch, tar or neat cement is packed in the space between the spirals of the spring, this material being held in position by small wires passed through holes bored in the periphery of the spirals. An anchor pipe of sufficient length to hold the packer in the desired position above bottom is screwed to the lower end of the supporting stem and the device is lowered while suspended from the drilling tools. When in place, a few blows with the tools break the wooden dowel, the stem falls through the spring into the anchor pipe, allowing the spirals to collapse and expand, pressing against the walls of the well and compressing the oakum between them. A little neat cement placed in the bottom of the hole with the bailer before placing the plug, so that the latter will be immersed in the liquid cement, further insures the success of the work.

Properties of Cements Used in Sealing Off Water in Oil Wells

In cementing oil wells, portland cement of a special grade is commonly used. Oil well cements should not set within a shorter period than 1 hr., and the initial set should occur within 5 hrs. The former limit is imposed in order that there may be sufficient time to place the cement and allow it to settle, and the upper limit is desirable in order that it will not be necessary to hold pressure on the casing or tubing for a prolonged period of time. Table XXIX gives the physical and chemical properties of several well-known brands of oil well cements commonly used in the California fields.[21]

Table XXIX.—Physical and Chemical Properties of Oil Well Cements*

Constituent	Formula	Brand of portland cement			Brand or source of hydraulic lime[d]				Common or quick lime,[e] per cent
		Golden gate cement,[a] per cent	Santa Cruz oil well cement,[b] per cent	Mount Diablo oil well cement,[c] per cent	German, per cent	Pacific Lime & Plaster Co., San Francisco, per cent	Cartersville, Ga., per cent	Mankato, Minn., per cent	
Silica......	SiO_2	20.89	19.38	22.36	25.87	19.51	15.04	18.10	1.00
Ferric oxide..	Fe_2O_3	3.37	5.31	2.51	} 8.13				
Alumina.....	Al_2O_3	7.09	7.15	7.17		12.40	.72	5.02	1.30
Lime.......	CaO	63.47	63.70	62.39	55.44	39.20	51.12	40.68	97.00
Magnesia...	MgO	1.32	2.13	1.39	1.14	20.61	29.53	29.17	.70
Sulphuric anhydride......	SO_3	1.19	1.48	1.45	1.44	1.65	Trace.	2.05	
Ignition loss...	...	1.54	1.04	2.09	1.96	.46	3.54	4.56	
Manganese oxide	MnO	...	..	.....	....	....	...	.42	
Carbon dioxide	..	....	...	..	6.02	6.17			
Specific gravity	...	3.12	3.20	3.12					

[a] Pacific Portland Cement Co., San Francisco, Cal. Analysis made by the company.
[b] Santa Cruz Portland Cement Co., San Francisco, Cal. Analysis made by the company.
[c] Cowell Portland Cement Co., San Francisco, Cal. Analysis made by the company.
[d] Analyses furnished by Dr. E. A. Starke, San Francisco, Cal.
[e] Marks, L. S., Mechanical engineer's handbook, 1916, p. 568.
* After F. B. Tough in U. S. Bureau of Mines, *Bull.* 163.

Variables Influencing the Setting Time of Portland Cement

The setting time of portland cement in oil well service is influenced by many variables, the more important of which are the chemical composition, the percentage of water used in the mix, the temperature, the age of the cement and conditions attending storage, and the size of the cement particles. The setting properties may also be influenced by contact with ground waters containing certain dissolved salts, or by the presence of flowing oil or gas.

From the chemical point of view, the setting time of portland cement is influenced by the percentage of free lime present, the alumina and silica content and the amount of gypsum or plaster of paris used in its manufacture. Deficiency of lime makes the cement quick setting if it is "under burned," or slow setting if it is "hard burned." Excessively high lime content tends to make the cement slow setting. High alumina content results in quick-setting properties, whereas a high silica content produces a slow-setting cement. Addition of gypsum or calcium sulphate up to 2 or 3 per cent retards the set, but further additions cause the setting time to decrease. Introduction of 10 to 20 per cent of plaster of paris will greatly hasten the setting time.

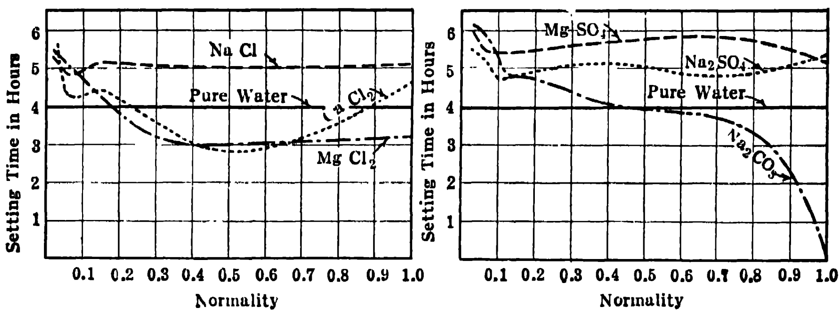


FIG. 148.—Graphs showing influence of dissolved salts on setting time of oil well cement.

The influence of saline ground waters on the setting qualities and life of portland cement in oil well service has been noted by many observers. Portland cements are quite sensitive to comparatively small percentages of some of these salts, and if there is any flow of saline water into the well during the placing and setting of the cement, its properties may be greatly altered. In extreme cases the cement does not set and must be pumped out of the well. Addition of small percentages of calcium chloride and sodium carbonate hastens the time of setting, but sodium chloride has the reverse effect. Contact with any sulphates will generally delay the time of setting. The graphs of Fig. 148 give the results of tests made with a typical oil well cement gaged with 50 per cent of water, containing varying percentages of dissolved salts commonly present in oil field ground waters. Tests made with a number of actual ground waters from the San Joaquin Valley fields of California showed in every case a considerable delay in the normal setting time (see Table XXX).*

Some of these salts, particularly salts of the alkalies and alkaline earths, in addition to influencing the setting time, will on prolonged contact with cement cause it to disintegrate.[18] Sulphates of magnesium and sodium, chlorides of magnesium and sodium, and carbonate of soda are particularly active in causing "unsoundness" in neat portland cement. Cements containing high percentages of ferric oxide in substitution for alumina are said to be more resistant to saline waters than ordinary cements. The sulphates and chlorides remove lime from the cement, while carbonate of soda withdraws silica. Unsoundness of cement may also be due to expansion as a result of belated crystallization of free lime and magnesia present in the cement itself. More than 5 per cent of magnesia is considered detrimental in a portland cement for this reason. Failure of the cement through such causes will not be apparent at first, but may eventually result in crumbling and disintegration and its ultimate failure in

* WRIGHT, F. L. and DEMARIS, E. L., Oil well cementing, *Thesis* prepared under the direction of the author, University of California, 1923.

water exclusion. The amount of "laitance", which forms on top of cement during the setting period is regarded as indicative of the degree of unsoundness of the cement.

TABLE XXX.—SETTING TIME OF CEMENT GAGED WITH TYPICAL OIL FIELD GROUND WATERS*

Dissolved salt	Sample number 1	2	3	4	5	6
	Grains per U. S. gallon					
NaCl	1,560 10	1,116 20	108 40	281 50	21 74	143 97
Na_2SO_4	. .	. . . .	3 31	.76	53 33	20.61
K_2SO_4						
$CaSO_4$	2 57	1 42	.	. . .	14 84	
$CaCO_3$	28 50	21 15	1 65	3 80	9 47	1.91
$MgCO_3$	8 93	1 92	.61	1 92	1 92	7 56
Na_2CO_3		14 30	41 64	121 80		351 42
$CaCl_2$	434 50	6 85				
$MgCl_2$	1 64	22 93				
$MgSO_4$			.	. .	9 44	
Fe_2O_3 plus Al_2O_3	2 05	1 20	10		2 27	.28
SiO_2	1 08	2 83	71	1 00	. .	3.07
Setting time, minutes	360	375	345	360	345	390
Increase in setting time,[a] per cent	150	156	144	150	144	162

[a] Setting time of the cement used when gaged with pure water was 240 min.; 60 per cent of water, by weight, used in each test.

* Samples 1, 3 and 4 are from the Midway field, California; 2 is from the Lost Hills field, California; and samples 5 and 6 are from the Coalinga field, California.

Dilution of the cement mixture with water prolongs the setting time. If the mixture is diluted to such a degree that the cement particles are held apart by suspension, they cannot be expected to form a coherent mass even though setting of the individual particles does occur. Though a smaller percentage of water would be preferable, a mixture containing 50 per cent of water (by weight) is about as thick as can be rapidly handled through pumps, piping and other apparatus used in oil well cementing. Such a mixture has a specific gravity of about 2.1. Tests made in the petroleum laboratory of the University of California* have shown, in the case of a typical oil well cement, that the setting time increases directly with the percentage of water, until the percentage of water reaches about 70 per cent; and that the setting time is only slightly influenced by further dilution (see Fig. 149). The cement-water mixture apparently becomes saturated when the percentage of water reaches about 60 per cent, additional water forming a clear layer above the cement grout on standing. The presence of too much water may prevent the formation of a coherent, solid mass,

* CERINI, W. F., An investigation of oil well cements, *Thesis* prepared under the direction of the author, University of California, 1923.

through the individual grains taking their initial set when not in contact. However, if there is adequate time for the cement particles to settle before the time comes for the initial set, a successful job is possible.

Though cement may be pumped into the well with only 50 per cent of water, it will frequently be further diluted by admixture with the well fluid and with the water used in pumping the cement down through the casing or tubing. It is well known that in pumping fluids through a pipe, the fluid near the center moves more

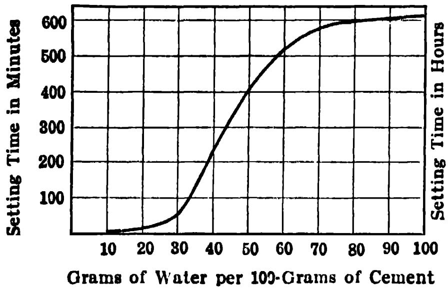


FIG. 149.—Graph showing influence of water dilution on setting time of oil well cement.

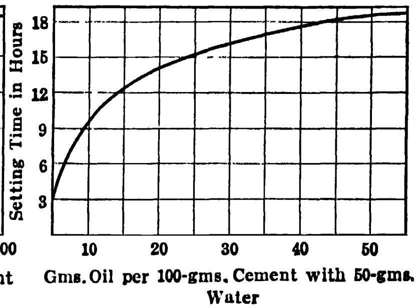


FIG. 150.—Graph showing influence of oil dilution on setting time of oil well cement.

rapidly than that near the walls of the tube, as a result of frictional resistance. Furthermore, turbulence is usually induced (see Chap. XVIII). Hence, when cement is pumped into a pipe containing water or mud, there is more or less dilution of the first portion of the cement introduced. A similar effect results when water is pumped in after the cement. The amount of dilution and admixture would vary with the diameter of the pipe and the velocity of flow, being greater in pipes of large diameter and at high-flow velocities. Even when barriers are used between the cement and the well fluid, as in the Perkins method, the two fluids must come into contact when the cement emerges below the casing shoe. Reversal in the direction of flow as the cement strikes the bottom of the well and is deflected upward, and contamination with mud from the walls as it rises, inevitably results in considerable dilution of the material that forms the top of the plug. Again, in the method of cementing direct through the casing without barriers, unless pumping is discontinued at the proper time, water forced in below the cement will rise slowly and become diffused through the latter by reason of its lower density.

Dilution with mud is not a serious matter, since cement will set even when contaminated with considerable amounts of mud. The mixture will be coherent and fairly impervious, but it lacks strength. Briquettes made of a mixture of equal parts of a mud-laden fluid of specific gravity 1.2, with a 50 per cent cement grout, had a compressive strength of only 97 lb. per square inch after setting 10 days in the air; while a pure 50 per cent cement grout, under similar conditions, had a compressive strength of 2,210 lb. per square inch. Probably only the upper portion of a cement plug is contaminated with mud to this degree, the heavier cement injected below the column of mud tending to float the latter, so that the lower part of the plug is fairly free of mud.

The setting time of portland cement is greatly influenced by temperature. As indicated by the graph given in Fig. 151, some cements set in one-third of the time at 150°F. that is required for the same cements at 60°F. While ground temperatures as high as 150° are perhaps uncommon in most oil wells, 100 to 125° is quite common in deep wells in some fields, and temperature is clearly an important variable that must be taken into account in cementing operations.

Portland cement in storage inevitably undergoes a certain change in chemical composition that greatly alters its setting time. This is due to hydrolyzing of the lime as a result of contact with moisture in the air. This change operates to prolong the necessary setting time. Certain cements stored in a dry room for a period of 6 mo. have increased their setting times from 2 to 4 and even 5 hr. in some cases. The rate of change is, of course, primarily influenced by the conditions attending storage. For uniformity in results, cement should be purchased direct from the manufacturers, and in quantities that will not require prolonged storage. This is particularly important when operating in moist climates. The place of storage should, of course, be absolutely dry.

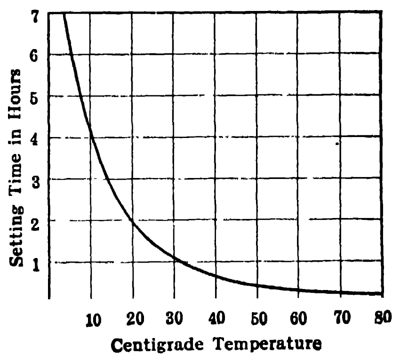


FIG. 151.—Graph showing influence of temperature on setting time of oil well cement.

The setting qualities of portland cement are also influenced by the degree of fineness to which the components are ground. Most cements are ground so that all but 2 or 3 per cent of the material will pass a 100-mesh screen, while about 80 per cent usually passes 200 mesh. The coarse material which does not pass 100 mesh is probably inert and never sets. Tests made by Meade[22] with a certain cement show a setting time of 30 min. when 95 per cent passes 200 mesh, while the same material ground so that only 75 per cent passes 100 mesh requires 170 min. in which to take its initial set. Uniformity in sizing is found to be one of the most important considerations in the manufacture of a reliable product.

Mixture of oil with portland cement slurry will not prevent setting, providing there is sufficient water present to hydrolyze the material properly, but it has the effect of prolonging the setting time. Figure 150 illustrates the effect of oil admixture in delaying the initial set of a typical oil well cement. Oil may also prevent the cement from adhering to the casing, leaving a crevice through which water eventually finds its way to the lower part of the well. Perhaps this leakage is negligible at first, but is later increased by the solvent action of percolating alkaline ground waters.

The presence of gas in the bottom of a well is a more serious matter. Violent agitation of the cement sometimes prevents it from setting into a coherent mass, while even comparatively small quantities of gas continually supplied from a point below the plug will, in seeking an outlet, leave pores in the cement which will later become channels for the passage of water. If a well is producing gas in quantity, it should be possible to hold pressure on it during the process of cementing, to prevent flow of gas. Preliminary mudding under pressure will often "kill" the gas so that cementing operations may be safely conducted at lower pressures.

Use of Hydraulic Lime in Excluding Water from Wells.—Occasionally it will be necessary to cement a well against the pressure of a strong flow of high-pressure water or gas. Perhaps there is only one string of casing in the well and it is impossible to close it in or to apply pump pressure. It may happen that mudding to "kill" the pressure is ineffective because the formation absorbs the well fluid and makes it impossible to secure circulation. In such a case, the operator may resort to the use of hydraulic lime as a means of sealing the walls and excluding the high-pressure gas

and water, so that portland cement later introduced may rest undisturbed during its setting period.

Hydraulic lime is manufactured by burning and hydrating lime rock, but the material is not sintered as in the case of portland cement. Table XXIX gives characteristic analyses. The calcium and magnesium are left in the hydrated form, as $Ca(OH)_2$ or $Mg(OH)_2$, but contain no water of crystallization. Unlike ordinary lime, hydraulic lime will set under water.

When hydraulic lime comes into contact with finely divided silica and the aluminum silicates of shales and clays, it reacts to form complex gelatinous silicates, which expand in hardening and fill the rock pores. By forcing it under pressure into a well, we thus convert the mud which lines the rock walls into a hard impervious sheathing, locked to the walls by penetration into rock pores and crevices in such a way as effectively to resist passage of fluids into the well.

In the practical application of hydraulic lime in excluding flowing water and preparing the well for a plug of portland cement, the lime is mixed separately with water and pumped into the well ahead of the cement.[21] The cement follows immediately behind the lime solution which adheres to the walls so that they present a well-consolidated surface to the cement. As a result, there is little tendency for the clay in the walls to dilute the cement, and the conditions for setting of the cement without agitation by high-pressure flowing water or gas are more favorable.

Hydraulic lime may also be used effectively in rotary drilling by admixture with the mud-laden fluid, in sealing "dry" sands which absorb the well fluid to such a degree that circulation is difficult or impossible.

Methods of Hastening the Hardening Set of Portland Cement.—The disadvantages of having to wait while the cement hardens for from 10 to 28 days before resuming drilling operations is regarded as a considerable hardship by operators anxious for early production. In order to reduce this loss of time, investigations have been conducted in the development of means of hastening the hardening set of the cement used. Calcium chloride or "Cal," an oxychloride of calcium ($3CaO.CaCl_2.14H_2O$), have the property of hastening the hardening set of portland cement without materially influencing the initial set, and without detriment to its strength and soundness. Tests made by the U. S. Bureau of Standards* have shown that mortar mixed with 5 per cent of "Cal" is after 2 days the equal in strength of untreated mortar after 8 days. Fifteen per cent of "Cal" gives an increase in strength of 220 per cent at the 2-day period.

The use of a somewhat similar reagent has been patented by F. H. Huber,[13] and is used by many California companies in oil well cementing jobs. In each cubic foot of water used in the mix, 3½ lb. of the reagent

* YOUNG, R. N., Effects of Cal as an accelerator of the hardening of portland cement mixtures, U. S. Bureau of Standards, *Technologic Paper* No. 174, 1920.

are dissolved, forming a solution having a specific gravity of about 1.03. Drilling is continued after 4 days when the reagent is used, while a period of from 10 to 15 days is customarily allowed for untreated cement to harden.

The strength of portland cement in oil well service is of less importance than its effectiveness in preventing seepage of water through it. This latter property, however, as well as its strength, is largely dependent upon density, and density is influenced by pressure. The lower portion of a cement plug is naturally denser than the upper portion, because of the greater amount of cement condensed within the liquid mass as a result of greater hydrostatic head, and also because of the tendency of the solid cement particles to settle before setting occurs. Tests made with a 14-in. column of cement showed a tensile strength of only 150 lb. per square inch for the upper section of the column, while a section from the lower end had a tensile strength of 280 lb. per square inch. Other sections cut at intervals between the top and bottom of the column indicated a fairly uniform increase in strength and density with depth below the cement surface.

The strength of cement is influenced by contamination with mud. The walls of the well usually contain large quantities of clay deposited from the well fluid. This is especially the case when the well has been drilled by the rotary method. Unless this mud is removed before the cement is introduced, it will mix with the cement forming the upper portion of the plug, diluting it and correspondingly reducing its strength.

Penetration of Wall Rocks by the Cement.—An important consideration in the formation of a cement plug to resist water infiltration is the extent to which the fluid cement penetrates the rock pores before setting. It is probable that under high pressures the cement not only fills the space within the well, but is also forced into all crevices and even into the pores of sands and granular wall rocks, thus forming what may be called a formation lock on the walls of the well. The extent to which this action will occur depends upon the excess of pressure within the well and the porosity of the wall rocks.

To be effective, the cement plug must at some point below the source of the water, be in contact with a relatively impervious stratum, otherwise water may find its way through the formation around the cement plug, and thence into the lower portion of the well below the plug. In an extension of the Kern River field of California this difficulty was experienced, but successfully met by forming long cement plugs about the casing and applying a pump pressure of 1,200 lb. per square inch (in addition to the natural hydrostatic head), which forced large amounts of cement into the wall rocks surrounding the well, thus preventing downward migration of water through the formation about the plug. The cement is introduced in this case by the top packer tubing method.

Preparing the Well for Cementing.—Before cement is introduced into a well, all surplus mud and sludge should be carefully bailed or flushed out, so that the cement will have free access to the walls. If the cement is to be pumped into the well, circulation must be established from the bottom of the well to the surface by pumping fluid under pressure through the space between the walls of the well and the casing. If the formation tends to absorb large quantities of fluid, this may be difficult or even impossible, but until a free path for the cement behind the pipe is assured, none should be introduced. Circulation may be established, but the flow may be through favorable channels on one side of the pipe or through spiral channels about the pipe. Large quantities of mud in this case will still be lodged about the casing, and as the cement is introduced it rises through the channels already established by circulation, and an irregular plug consisting partly of cement and partly of mud will result. Water strings pulled from wells after unsuccessful cementing jobs have shown clearly in certain instances the spiral contact of the cement against the casing. This can only be avoided by continuing circulation of the well with clear water prior to cementing, until all mud is removed.

If the casing is nearly as large in diameter as the well, there is danger of the pipe making contact with the walls on one side or another, so that when the cement is introduced it does not form a plug concentric with the axis of the pipe. As a means of preventing this, it is a good plan to under-ream the hole for 25 or 30 ft. above the bottom, thus assuring sufficient free space to form a plug which will be thick enough to be effective on all sides of the casing.

Mixing the Cement

The method provided for mixing the cement must be capable of rapidly and thoroughly accomplishing its purpose, so that the entire amount of cement to be used may be in place in the well within an hour of the time that mixing begins. This is essential, since a successful result is impossible if the cement takes its initial set before it reaches its intended position. Several different types of equipment are in use for mixing and placing the cement in the well.

The Perkins Cementing Outfit.—With the Perkins equipment, the cement is mixed by hand methods, a group of from 4 to 6 men distributed about two flat metal or wooden boxes (10 ft. long, 6 ft. wide and 2 ft. deep) stirring with hoes, while water is added to the dry cement previously dumped into the box (see Fig. 152). Batches of cement are mixed in each box alternately.[21] While mixing is in progress in one box, one of the pumps is engaged in drawing mixed cement from the other. Either of two pumps mounted on the bed of a motor truck, is used in forcing the cement into the well, one a low-pressure pump capable of operating against a pressure of 250 lb. per square inch, and the other a high-pressure pump designed to meet pressures as high as 1,000 lb. per square inch (see Fig. 153). The suction lines of the pumps are

manifolded so that either may draw mixed cement from a small metal tank placed below the mixing tanks, in such a way as to receive the flow of cement from either tank when the wooden plugs controlling the discharge outlets are withdrawn. To gage the water used in mixing the cement, a water meter or a gaging tank is used. The water is passed through one of the pumps to give it pressure sufficient to permit of it being forcefully sprayed through a hose and nozzle into the dry cement in the mixing tanks. Operating systematically on a pile of dry cement, a single man is by this means able to mix the cement rapidly and thoroughly.

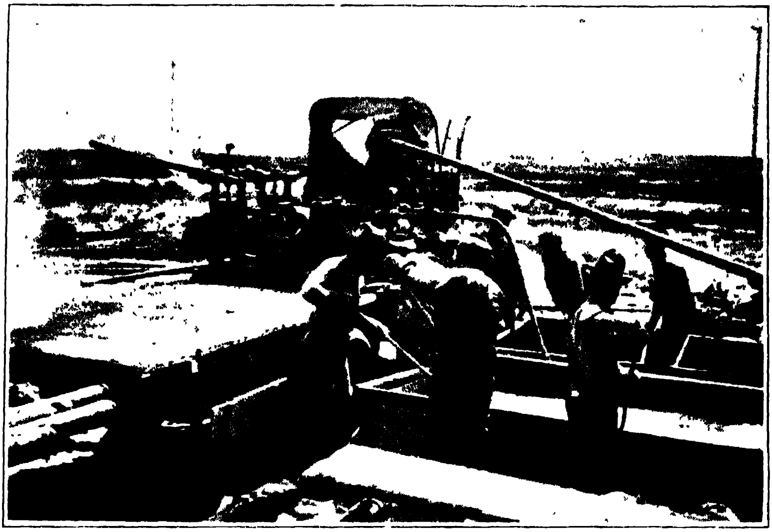


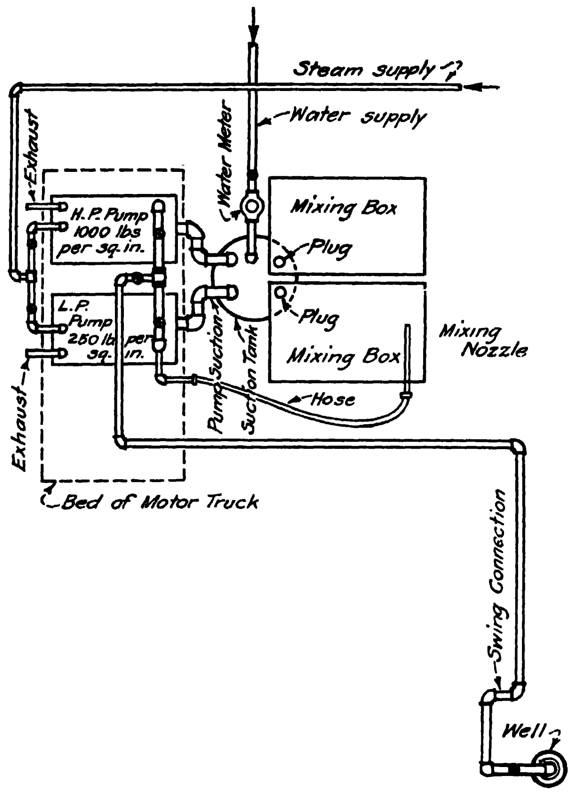
FIG. 152.—Perkins' equipment for mixing and pumping cement.

The mixed cement is passed ordinarily through the low-pressure pump, but if for any reason pressures in excess of 250 lb. per square inch are necessary, the high-pressure pump will be brought into service. Fittings and valves on the piping connecting with the cementing head on the casing must be capable of withstanding pressures in excess of the maximum delivery pressure possible with the high-pressure pump. Connections with the well must be flexible so that the casing may be raised or lowered when necessary. A union in the delivery line near the cementing head permits of readily disconnecting the pipe to insert the wooden plugs.

As the cement is pumped into the casing, being denser than water, it tends to sink into and displace the well fluid, so that very little pump pressure is necessary. However, this effect gradually diminishes as the work proceeds, until equilibrium is established and the pump pressure must be gradually increased. Pressures of from 200 to 250 lb. are often reached in a deep well, before the plugs come together. When this occurs, there will be a sudden increase in pressure, perhaps stalling the pumps and indicating satisfactory completion of the work. The casing is then lowered to bottom and the valve on the delivery line at the cementing head is closed to maintain pressure within the casing until the cement sets.

While, if all goes well, the operator may depend upon the action of the plugs and the pumps to indicate when all cement has passed out of the casing, yet it is a good precaution to have some means of checking the progress of operations, that may be relied upon when something goes wrong. Possible accidents which may prevent the orderly completion of the work include caving of the walls of the well,

preventing circulation, splitting or parting of the casing, "hanging up" of the plugs as a result of some obstruction in the casing or falling of the plugs through the shoe as a result of the latter being too far off bottom. As a precaution, it is customary to calculate the volume of the casing and that of the cement pumped into it. The water pumped down on top of the cement is also gaged or metered. By comparison of these volumes, the operator will be able to determine when the first or lower plug is approaching the lower end of the casing, and will lower the column until the shoe



(*After F. B. Tough in U. S. B. Mines Bull.* 163).

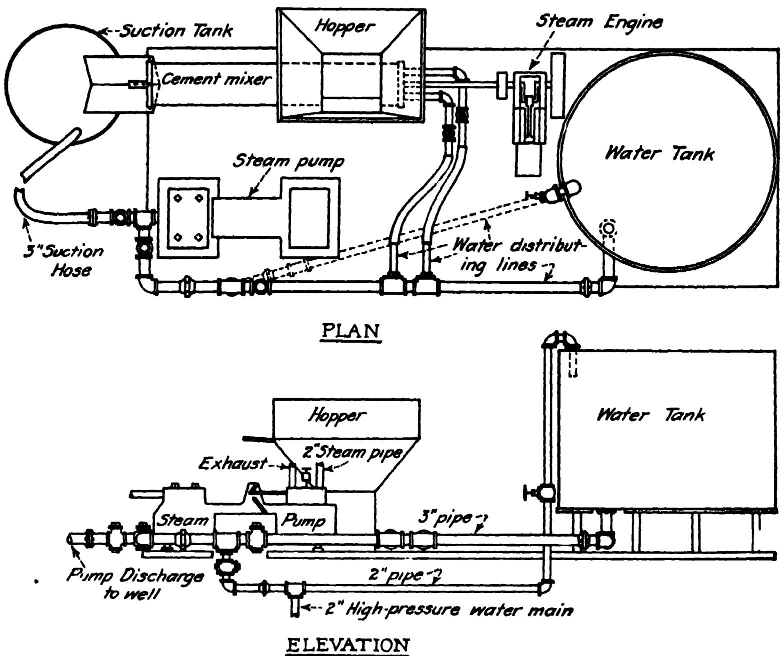
FIG. 153.—Arrangement of pumps, mixing boxes, piping, etc. for cementing wells by the Perkins process.

is only about 18 in. off bottom, thus preventing the upper end of the plug from escaping from the casing. He may determine, also, when the two plugs should come together, indicating that all cement is out of the casing.

W. B. Wygle, a California contractor, has patented a device for releasing the second Perkins plug from a nipple placed above the cementing head, so that it is unnecessary to uncouple the pump connections after the cement has entered the casing. The plug is held in the nipple by a set screw, which is loosened when it is desired to drop the plug into the casing. It is the opinion of some operators that air entering the pumping circuit at this time forms voids in the cement about the casing shoe. The Wygle device prevents this and expedites the work of placing the cement.

Another method of avoiding air pockets in the lower part of the cement plug, is to introduce a "spacer" of 2 in. by 4 in. or 4 in. by 4 in. timber about 20 ft. in length, between the two Perkins plugs. This leaves the latter part of the cement, which is likely to contain air, within the casing, later to be drilled out with the drilling tools.

The Scott Cementing Apparatus.—Cement equipment designed and used by W. F. Scott, a contractor operating in the California fields, is illustrated in Fig. 154. It



(*After F. B. Tough in U. S. B. Mines Bull* 163).
FIG. 154.—Scott cementing apparatus.

consists[21] of a mechanically driven cement mixer, comprising a hopper into which the cement is dumped and a tubular mixing barrel in which it is mixed with water by the action of revolving blades mounted on a longitudinally placed steel shaft (see Fig. 155). A small steam engine supplies the necessary power. Water flows into this mixing barrel from a large gaging tank. The cement flows from the mixer into a small cylindrical tank, from which it is taken into the suction line of a steam-driven reciprocating pump and pumped into the well. A suitable manifold and valve control on the pump suction line makes it possible to pump water from the storage tank directly to the well when desired. The entire apparatus may be mounted on a motor truck or wagon. Outfits of this type operated by Mr. Scott are able to mix a ton of cement in from 2½ to 3 min.

Mr. Scott has also developed and successfully applied methods of cementing through tubing and casing without barriers. In preparation for cementing operations, the equipment as described above is set up near the well and connections made with the local steam and water lines and from the pump to a cementing head placed on the casing. If the well is a deep one, it may be necessary to provide a larger water storage tank than the one which is commonly carried with the outfit. The

tank should be large enough to contain water sufficient for mixing the cement, and to fill the tubing or casing used in conducting the cement, with an excess of at least 10 per cent. Since the mixing machine works very rapidly, one sack of cement being mixed every 8 or 9 sec., the sacks should be opened before mixing is begun and placed on or near a platform built around the hopper of the mixing machine. The work of feeding the machine is tiring and four men should be provided to handle the cement, two working at a time and relieving each other frequently. Before the work is begun, computations are made of the volume of the tubing or casing through which the cement is pumped, and the equivalent, expressed in inches of depth of the water storage tank, is determined.

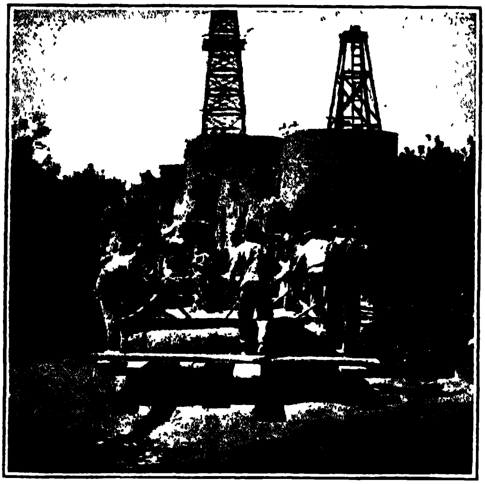


FIG. 155.—Scott's equipment for mixing and pumping cement.

With all in readiness, circulation is first established through the well, the cement mixer is placed in operation, and as the mixed cement is made available to the pump suction, the manifold valves are manipulated so that cement is pumped into the well without interruption in circulation. After all the cement has passed through the pump, reversal of the valves connects the pump suction with the water supply, again without interruption in circulation. The pump works continuously from the start of operations until the casing is lowered to bottom. If the tubing method is employed, as explained on page 272, the pumps may continue in operation after the casing is landed, until any excess cement which may be left between the tubing and the casing is returned to the surface.

Other methods of mixing cement have been used with more or less success. The Shell Company of California has employed an ordinary cement mixer, such as is used in mixing cement for building and road construction. The cement flows from the mixer into a wooden trough, where it is given further mixing by men equipped with hoes. The steam pumps, mounted on a wagon, pass the mixed cement under pressure from the lower end of the trough to the well. Some operators use the pumps to aid in mixing, a hose on the discharge manifold returning the cement to the mixing box from which the pump suction draws its supply. When this method is employed, all of the cement must be mixed before any is pumped into the well.

PLANNING A CEMENTING JOB

Before the exclusion of water is attempted in a well, the work should be carefully planned in order to insure its successful completion. The landing depth for the shoe of the water string must be selected so that it will rest in a stratum impervious to the passage of water. The desirable length for the cement plug should be determined, and the necessary

amount of cement calculated to form a plug of this length for the size of casing in use and in the size of hole being drilled. The physical conditions to be encountered should be carefully studied. Important factors to consider include the temperature at the depth where the cement is to be placed; the possibility of contamination of the cement with saline ground water before setting, or of it being subjected to agitation by strong flows of gas or water during the setting period; the condition of the bottom of the hole and of the casing; and whether or not it is possible to establish circulation between the casing and the walls of the well by the application of pressures within reach of the pumping equipment available. If any one of these factors is unfavorable, it may defeat the purpose of the work unless its influence is considered and preparations made to counteract it at the proper time.

A sample of the cement to be used should be tested to determine its setting time and soundness. If possible, a sample of the well fluid from a point near the proposed shut-off should be secured, and used in mixing the cement slurry to determine the influence of any dissolved salt, which may be present, on the setting time.

In calculating the amount of cement necessary, it is well to assume that the cement plug will extend entirely through the water sand to be cased off, and preferably to some distance above. If analysis of the waters in the sands above the point selected for the shut-off shows that they contain salts which will have a corrosive effect on the casing, it will be advisable to protect the pipe from them by forming a long sheathing of cement about it. In such cases enough cement may be introduced to form a plug several hundred feet long. In some instances the entire space back of the pipe up to the surface has been filled with cement, with the purpose of protecting the casing against rapid corrosion. Having determined the necessary length of plug to provide, and knowing the size of the casing and the diameter of the well, the volume of the cement plug to be formed is calculated. When 75 to 80 lb. of dry portland cement is mixed with 60 per cent of water it forms 1 cu. ft. of neat cement, when set and hardened. One sack of cement mixed with ½ cu. ft. of water forms about 1 cu. ft. of grout. Mixed with 60 per cent of water, it occupies 1.15 cu. ft. A ton of cement, when mixed with 60 per cent of water, occupies from 23 to 30 cu. ft. Table XXXI gives other useful data on cement-water mixtures. The amount of cement necessary will depend chiefly upon the size of the casing. For California practice, the quantity used in cementing water strings varies from as much as 12 tons for 10-in. casing, to as little as 2 tons for 4¼ in. In the Gulf Coast fields, 40 to 50 sacks, or about 2 tons, are commonly used in cementing a 6-in. string.

TABLE XXXI.—WEIGHT AND VOLUME EQUIVALENTS OF OIL WELL CEMENTS

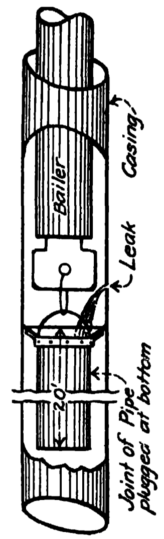
	Weight, lb.	Volume, cu. ft.	Weight per cubic foot, lb.
1 sack of cement (dry volume)	94 0	0 9464	99.32
1 sack of cement with 40 per cent of water (by weight)	131.6	1.1167	117.84
1 sack of cement with 50 per cent of water (by weight)	141 0	1.2682	111.17
1 sack of cement with 60 per cent of water (by weight)	150.4	1.4196	105.94
Water Necessary for Various Cement Mixtures			
	Gal.	Cu. ft.	Weight, lb.
1 sack of cement with 40 per cent of water (by weight)	4.51	0.603	37 6
1 sack of cement with 50 per cent of water (by weight)	5.64	0.754	47.0
1 sack of cement with 60 per cent of water (by weight)	6.77	0 905	56.4

NOTE.—In this table, the specific gravity of oil well cement is assumed to be 3.174.

TESTING EFFICACY OF WATER SHUT-OFFS

On completion of a cementing job, or other work designed to exclude water from a well, a test should be made to determine whether or not it has been successful. If cement has been used, such a test should not be made until it has had time to set and harden properly. Any cement left within the casing is first drilled out, and a hole drilled for a depth of 10 or 20 ft. ahead of the shoe of the water string. The fluid is then bailed from within the casing until the level is sufficiently below that at which the fluid stands outside of the casing to allow water to enter if it is able to do so. After bailing, the fluid level within the casing is carefully measured and recorded. The well is allowed to stand 24 hr., and a second measurement of the fluid level within the casing is made. If the level has not changed materially, the shut-off is regarded as successful. Draining of films of water down the inner walls of the casing after bailing may raise the fluid level slightly. Even though a slight leakage of water under the shoe is apparent, it may be considered too slight to justify further repair work.

Measurement of fluid level within a casing may be made with the aid of a heavy plumb bob and a steel measuring line, on a suitable reel mounted above the well mouth on the derrick floor (see page 133). If cable drilling tools are available, it is customary to make fluid level measurements with the sand line and bailer. The bailer is run into the well until it is submerged or partially submerged below the water level. A mark is then made on the sand line level with the derrick floor, and as the bailer is withdrawn from the well, the length of line is measured below this point to the point where first moisture on the line or bailer shows the water level to have been. The process of measuring the sand line is readily accomplished by determining the length of line from the derrick floor up over the crown block, and down to the level of the sand reel flanges. This unit of measurement is applied by tying a strand of manila fiber to the line at the level of the derrick floor, and raising the bailer until this strand reaches the sand reel flange. The strand is then removed and another placed on the sand line level with the derrick floor; and the process is repeated until the wet portion of the cable or bailer emerges. The number of strands untied from the line at the sand reel, plus one, multiplied by the unit length over the crown, plus the fractional interval from the last strand down to the derrick floor (as measured with the gage stick or tape), is the depth to water level.



(After R E Collom, California State Mining Bureau, Dept. of Oil and Gas).

FIG. 156.—Illustrating method of using casing tester.

Repairing Unsuccessful Shut-offs

If tests made as outlined above indicate that the effort to exclude water has not been successful, further tests must be made to determine the nature of the difficulty. Perhaps, due to one or another of the physical and chemical variables already discussed, the cement has not set; or, if it has set, open channels may have been left through it. Perhaps the cement plug is structurally misplaced and the water is coming from formations below the plug. Occasionally, casing leaks above the shut-off will admit large quantities of water.

In locating the source of water entering a well, tests should first be made to determine whether or not the casing leaks. Testing for casing leaks may be conveniently conducted with a casing tester (see Fig. 156), which is alternately lowered to successively greater depths and hoisted to the surface until it brings up water. The casing may have become worn through by abrasive action of the drilling cable; or it may have split at a defective weld, or as a result of application of a swage; or the leak may be at a loose collar which is cross-threaded, or which has become unscrewed in the well.

If the leak is not in the casing, a test should next be made to determine whether water is finding its way down through or around the cement plug and under the casing shoe, or whether it comes from some lower source. For this purpose, a "bridge" should be placed a few feet below the shoe, sealing off the hole that has been drilled below. This plug is built up from bottom in successive stages with the aid of wooden or lead plugs and cement. If further tests indicate that water has been excluded by this process, it may be concluded that the shut-off has been placed too high, and that water-bearing formations occur below the casing shoe.

The nature of the remedial measures to be taken depend upon the source of the water and the way in which it finds admission to the inner portion of the casing. If cement has been used and has failed to set, it will be possible to raise the casing, bail out the cement and repeat the cementing operation after studying the cause of the failure and making such changes in methods or materials as seem desirable. If the cement has set properly but has been ineffective, a more difficult problem is presented. If tests indicate that water is entering under the shoe, it may be possible to force cement back of the shoe under pressure, using the top packer tubing process; but this procedure will usually not be effective unless it is possible to secure circulation through the defective cement plug.[20] If the cement plug is a short one, it may be possible to part the casing above the cement with the aid of explosives and so shatter the detached casing and cement that it can be "drilled up" or "side tracked;" but usually this will not be possible and it will be necessary to "sacrifice" a string of casing by cementing a smaller water string below the first.

If water is entering through a leak in the pipe and not around the shoe, and the hydrostatic head likely to be developed above the leak is not great, drilling may be continued and the well completed in the usual way. The inner string of casing, or "oil string," may then be extended to a point above the leak in the water string and mechanical packers set between the two to exclude water. If this procedure is considered unsafe, due to the size of the leak and the hydrostatic head likely to be developed above it, a bridge should be placed in the casing immediately below the leak and an effort made to force cement through the hole in the hope of forming an impervious layer of cement on the outside of the pipe. If the hole is small, application of a casing perforator or ripper will form larger holes through which cement will pass. If it is suspected that water is entering the well through a loose coupling, it may be possible to remedy the difficulty by giving the casing a few turns at the surface.

Some of the most difficult and uncertain cases are encountered in attempting to shut off water which occurs as intermediate water in a zone of productive oil sands, or in the base of a thick productive stratum. Here every precaution must be taken to avoid cementing the productive sands. In some cases, also, top waters are separated from the oil zone by only a few feet of impervious material, and very accurate knowledge of the depths and thicknesses of strata is necessary to "land" the water string and cement it before it enters the oil zone, and still be assured of placing the plug so that it is continuous throughout the water zone.

When drilling in territory in which the stratigraphy is not definitely known in advance, a well will sometimes be drilled below the logical point for a water shut-off before the necessity for it becomes apparent.[15] In such a case, it is necessary to withdraw the casing until the shoe is at the desired level and then plug or "bridge" over the lower portion of the hole before introducing the cement.

Importance of Stratigraphically Uniform Shut-Offs in Contiguous Wells.—A study of the possibility of water migration from well to well through porous strata will indicate the importance of stratigraphic

uniformity in the placing of water shut-offs. Fig. 157 illustrates some of the cases arising from failure on the part of the neighboring operators to recognize the necessity for cooperation in deciding upon the selection of a particular stratum in which to make all water shut-offs. Correlations for this purpose, and determination of landing depths for water strings, constitute an important aspect of systematic water exclusion. Such work should be entrusted to some state or semi-public technical commission rather than left to the whim of individual operators. In California, the depth at which the water shut-off is to be made in every well is specified by the State Oil and Gas Supervisor or his deputy.

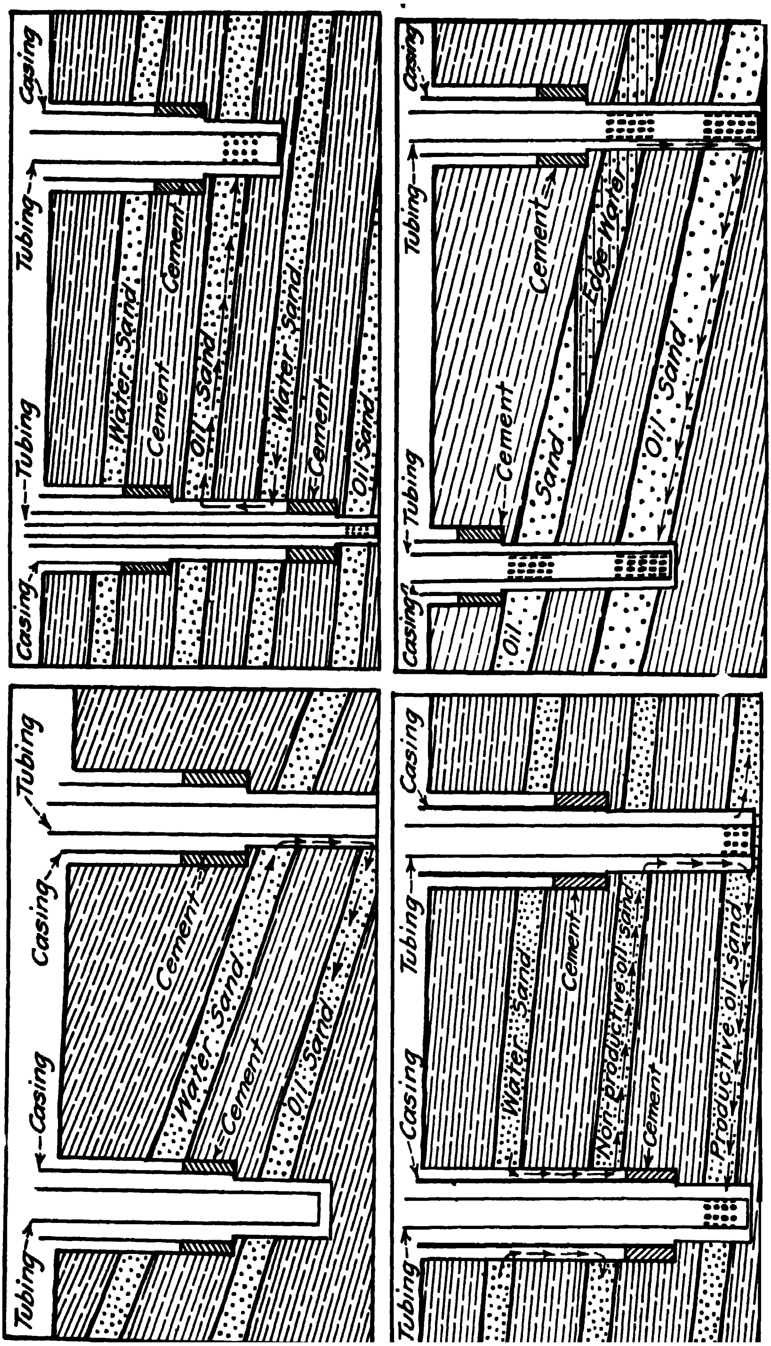
Exclusion of Water from Wells by Mudding

The action of circulating mud-laden fluid under pressure in closing the pores of granular rocks has already been discussed in connection with rotary drilling. Use of mud in this way has also been successfully applied in the permanent exclusion of water as a substitute for the cementing process.

In one instance described by A. W. Ambrose,* a well in the Coalinga field of California was drilled to produce from the lower of two oil sands, between which there is an intermediate water sand. The well was drilled through both the upper oil sand and the intermediate water sand before any cement was placed, security against admission of water into the upper oil sand being assured by a thorough mudding of the oil and water sands while drilling through them with rotary tools. By this method a string of casing costing $6,000 was saved. When the cement was placed to protect the lower oil sand, sufficient was used to form a plug extending up through the upper oil sand. A near-by well, only 150 ft. distant, producing from the upper sand, provided a means of testing the efficacy of the mud. For a time while mudding was in process, the near-by well produced considerable quantities of muddy water, but flow between the two wells ceased before the process was completed.

In the development of certain California fields, where upper oil and gas strata are cased off behind a water string to obtain production from a more productive lower zone, it has become the custom for operators thoroughly to mud the upper formations under pressure in order to prevent intermingling of fluids from different beds above the shut-off. This practice saves one or more strings of pipe that must otherwise be cemented between the several zones, and gives ample protection to operators producing from the upper beds. More than 600 wells have been so treated in the California fields during recent years, and the records of the State Oil and Gas Supervisor's Department show that in

* U. S. Bureau of Mines, *Bull.* 195, p. 157.

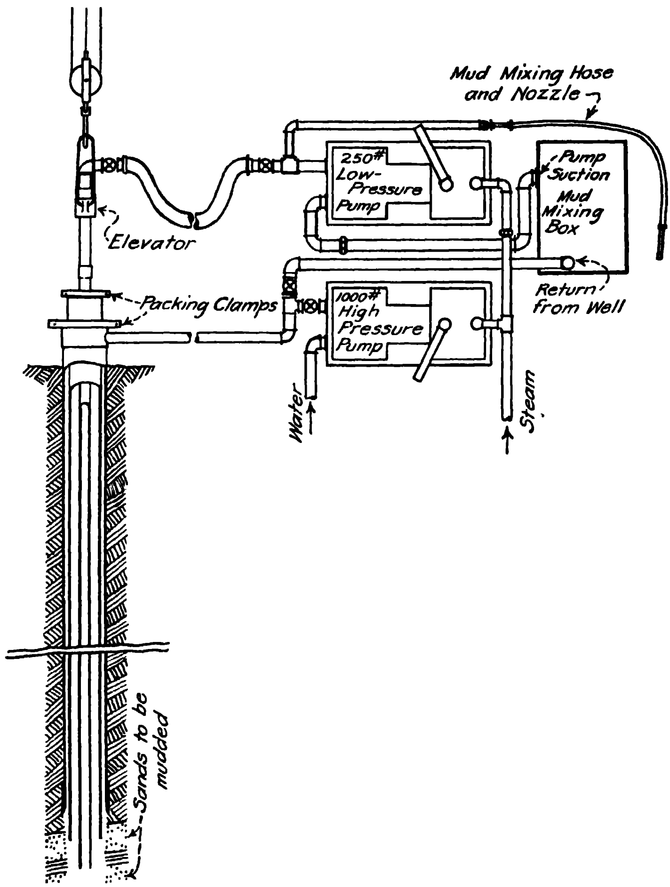


(*In part after R. P. McLaughlin, California State Mining Bureau, Dept. of Oil and Gas*).

FIG. 157.—Illustrating manner in which water may migrate from one well to another.

upwards of 85 per cent of the wells the mudding has apparently accomplished its purpose.*

The mudding process may be conducted through casing or rotary drill pipe by continued circulation as in rotary drilling; or by using a circulating head and throttling the outlet, an additional pump pressure of several hundred pounds may be held on



(*After H. J. Steiny, California State Mining Bureau, Dept. of Oil and Gas*).

Fig. 158.—Arrangement of equipment for mudding under pressure with circulating head.

the well while the fluid is circulated (see Fig. 158). Circulation is usually down through the casing or drill pipe and back to the surface between the pipe and the walls of the well; but in some cases it has been found advantageous to reverse the direction, pumping down through the annular space between the conductor string and the inner pipe.†

* Collom, R. E., Mud fluid for rotary drilling, *Summary of Operations, California Oil Fields*, vol. 8, no. 7, Jan., 1923. (With a report on the use of mud-laden fluid in the California fields by a special committee of engineers.)

† See References 6 and 9 at end of Chap. X.

Some operators recommend mudding under a pump pressure of from 200 to 300 lb. per square inch, continuing circulation until the formation absorbs less than 2 bbl. of fluid per hour. This is not always possible, though in many cases the volume of fluid absorbed has been reduced to less than 1 bbl. per hour. This condition is often reached after 10 hr. of continual circulation under pressure, but in extreme cases may require a week or more. It should be pointed out in this connection that the quantity of fluid absorbed by the formation will vary with the wall area exposed, that is, with the depth or thickness of exposed rock face and the diameter of the well. Absorption and the degree of penetration obtained will also vary with the porosity of the beds penetrated, and with the pressure of the fluids stored within them.

A more effective mudding action of the circulating fluid may be secured by the addition of alkaline substances which serve as coagulants for the clay particles. Hydraulic lime has been effectively used for this purpose, forming a sticky, pasty clay that rapidly clogs all rock fractures and crevices. It has been suggested that a coagulating chemical be injected into the mud fluid in the bottom of a rotary drilled well during the process of cementing, pumping the reagent down through the casing just ahead of the cement. The clay would be thereby rapidly settled into an impervious mass on top of the cement plug, adding to its effectiveness.

In cases where oil and gas sands have been mudded off behind the water string at some distance above the cement plug, mud is sometimes pumped down between the conductor pipe and the water string, until the formation does not absorb further fluid. The space behind the water string is thus left filled with heavy mud, which effectively prevents intercommunication of fluids between the strata penetrated. Wells so mudded have maintained the same fluid level behind the water string for years, proving conclusively the effectiveness of the process.

Protection of Oil Sands against Water Incursion in Abandoning Wells. After production declines to a point where operation is no longer profitable, precautions should be taken against water incursion before the well is abandoned. It is customary to salvage as much of the casing as can be recovered, and since withdrawal of the casings will admit water to the oil sands, the wells must be plugged. Even though the water string is left intact, corrosion will eventually result in failure of the casing to retain the fluids of the overlying formations.

The well is preferably plugged with cement to a point above the cap rock immediately overlying the oil zone, the cement being mixed and placed in the well by either of the methods described in the foregoing pages. Dump bailers are often used for this purpose, though the cement is more expeditiously inserted by pumping through tubing.

There is good reason to believe that the oil measures may be adequately protected in abandonment proceedings, by mudding under pressure, a process that should be somewhat less expensive than plugging with cement. A hole left full of thick mud, after circulating until absorption of fluid by the wall rocks practically ceases, offers little opportunity for intermingling of fluids from different horizons; and if there is sufficient clay in the fluid to fill the hole, after settling, to a point well above the top of the oil sand, the clay plug so formed should offer ample protection against water incursion from above. However, it is not

always easy to mud an exhausted oil sand, so that it does not continue to absorb fluid; and unless the wall rocks may be made practically impervious, the mudding process cannot be relied upon for permanent protection.

Locating the Source of Water in a Flooded Well or Group of Wells

In many cases it is a difficult matter to determine the source of water which is finding its way into an oil well. Occasionally, large quantities of water will be admitted to the productive oil sands through a single well, and neighboring wells will be influenced, perhaps cutting off all production from an entire group within a few months' time. It is evident that such a condition will occasion large losses, and there will be ample justification for the expenditure of a considerable sum in repair work, if by so doing the condition can be remedied. When such a situation presents itself, it usually requires a careful study of all of the available information to determine which well is at fault, and when this is done to locate the source of the water.

In determining which well of a group is admitting water to the productive strata, recourse may be had to several methods of procedure. A close stratigraphical correlation of water shut-offs with the aid of a peg model may disclose the fact that in one well the cement plug, provided to exclude top water, has been placed too high, or that the well has been drilled into bottom water. A study of the drilling history of each well may disclose facts which will aid in reaching a conclusion. Perhaps a water string has corroded to such a degree that water has found admission, or it may be that a cement plug has disintegrated as a result of the use of unsound cement, or by contact with alkaline ground waters. Again, if the wells are producing from several different sands comprising a zone, an edge-water condition developing in one sand may occasion apparent flooding of others. For example, in the sketch reproduced in the lower right of Fig. 157, edge water in the upper sand in the well at the right may eventually flood the lower sand in the left-hand well. A carefully kept series of production records giving the amounts of water and oil produced by each well of a group will be of great assistance in determining which well or wells were first influenced, and which produce the largest percentage of water. Attention can then be focused on these as likely offenders. A study of fluid levels in a group of wells will often disclose the faulty well as the one having the highest fluid level.

Use of Dyes and Dissolved Salts as Flow Detectors.—It is occasionally possible to prove that water is flowing from one well to another by inserting an easily detected dye or chemical substance in the well from which the water is flowing, and observing its later appearance in the water pumped from surrounding wells.[1] This is a test that

may be applied after attention has been focused on the offending well of a group by a close study of the evidence.

The dyes commonly used are fluorescein, eosine, magenta and other fluorescent organic dyes. Fluorescein,[4] which has a distinctive yellowish-green color by reflected light, is apparently best adapted to the purpose. It can be detected in water by the naked eye when present to the extent of 1 part in 40,000,000, and with the aid of the fluoroscope, 1 part in 2,000,000,000 can be detected. Furthermore, it is not appreciably adsorbed by clays, and may travel for a considerable distance under ground without change in its physical properties. Eosine is a brick-red dye that is not quite so easily detected in minute quantities as fluorescein. The dye should be dissolved in a bucket of water and either poured into the well, or lowered in a glass container on the bailer or a cable drilling bit. On reaching bottom, a blow with the dart of the bailer or with the bit breaks the container and liberates the dye. The amount of dye necessary will depend upon the quantity of water the wells are producing, and upon a consideration of the opportunity for diffusion and the concentration necessary to produce an easily detected color. Usually a great excess is used—from 15 to 100 lb.—as a precaution against loss through adsorption, diffusion and dissipation in other ways. Instances are on record where dyes used in this way have passed through the earth over distances as great as 900 ft. in about 3 hours' time.

A similar use of various soluble salts, such as lithium, sodium, calcium or ammonium chlorides or nitrates, has been suggested, identification of the foreign substance in the ground water being effected by chemical analysis.

It should be pointed out that the use of dyes and other flow detectors in tracing the movement of underground water is more or less unsatisfactory since the results are too often negative. If the detector can be shown to have moved from one well to another, it will have served its purpose, but if the result is negative and the detector does not appear, there is always the uncertainty of whether or not some unforeseen factor has prevented it from having proper access to the water channels, or whether it has been subjected to conditions which may have changed its physical or chemical characteristics.

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CHAPTER X

CONTROL OF HIGH-PRESSURE WELLS

On drilling into a stratum containing oil or gas under high pressure, precautions must be taken against loss of control which might result in waste of oil and gas and serious damage to the well and its equipment, as well as to surrounding property. Preventive measures are of two sorts: first, the use of methods which prevent the destructive forces from becoming operative, and second, the provision of safeguards which will make possible their control if they do become operative.

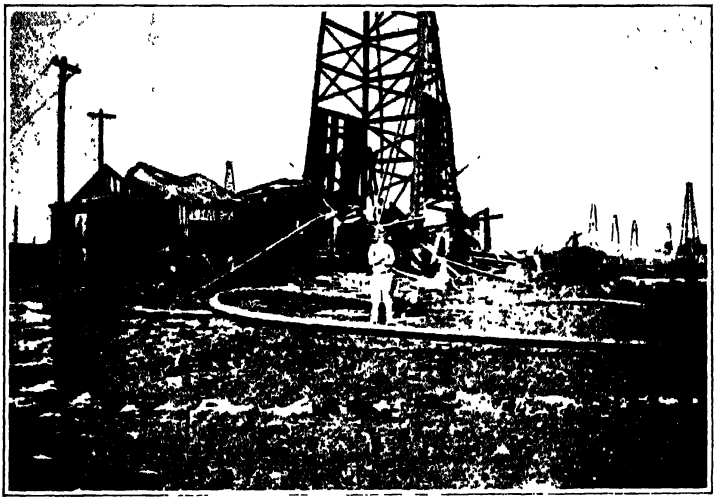


Fig. 159.—Illustrating wreckage of surface equipment after a blow-out. Note coiled rotary drill pipe in foreground.

A high-pressure well out of control may prove exceedingly destructive. Violent ejection of the well fluid, perhaps accompanied by flows of sand, oil and gas, sometimes shatters the derrick, occasionally burying the drilling equipment (see Fig. 159). The drilling tools, rotary drill stem, and at times even the heavy casings, have been lifted bodily out of the well by the forces developed. Lack of control at such times often permits large quantities of sand to "heave" into the well, or the walls may cave or the casing collapse, necessitating redrilling, or, in extreme cases, even abandonment of the well. Blow-outs of high-pressure gas flowing around the outside of the well casings occasionally form craters which fill with water or oil and completely engulf the rig and its equipment (see Fig.

160). Oil jetted high into the air from the well is caught by the wind and sprayed over the surrounding terrain, carrying destruction to trees and crops, and necessitating repainting of buildings. At such times, fire frequently adds to the destruction. A static spark resulting from friction of gas at the casing head; a spark caused by the striking of metal on metal, or rock on metal; or a flow of gas coming into contact with the boiler fires, the forge or other naked light—and the well and everything reached by the oil is converted into a mass of flame. Such conditions sometimes develop in so brief a space of time that they become a menace to the lives of the drillers. Once out of control, the flow of oil and gas may continue for days, weeks or even months, the damage wrought to the well equipment and difficulty of approach often making possible remedial measures ineffective.

FIG. 160. Crater formed about a well after a blow-out and fire.

Casing Head Valves and Mechanical Control Devices

These devices are widely used as a precautionary measure on wells drilled in a high-pressure territory. They are intended to restrain temporarily the expulsive forces, by closing in the outlets at the well mouth until such time as corrective measures can be applied or permanent controls provided. To serve its purpose, such a device must permit of drilling operations being conducted without interference; it must provide prompt control in an emergency, and it should be strong enough to withstand the pressures to which it is likely to be subjected.

The Control Casing Head.—For use on wells which are expected to encounter high pressures, drilled with cable tools, a control casing head is often employed (see Fig. 161). This consists of a heavy casting in the form of a four-way tee which screws on the top of the working string of casing, the space between this and any larger string that may be in the well being closed with a packing ring screwed into the larger casing head. A special cylindrical valve, operated by a stem extending through a stuffing box in one of the side outlets, may be adjusted by a quarter turn to close either the top or bottom outlet of the tee, the side outlet being always open. A groove cut in the valve, large enough to admit the drilling cable, permits it to close when the drilling tools or bailer are in the well, without injury to the cable or sand line. By

providing a 20-ft. extension of the valve stem, the valve may be manipulated from outside of the derrick. With the valve turned so that both upper and lower outlets of the tee are open, drilling operations may be conducted without interference. In the event of a sudden flow of fluid from the well, with the tools either in or out, by a quarter turn of the valve the well will be shut in or the flow may be diverted through the side outlet, and through a connecting lead line to a tank or sump.

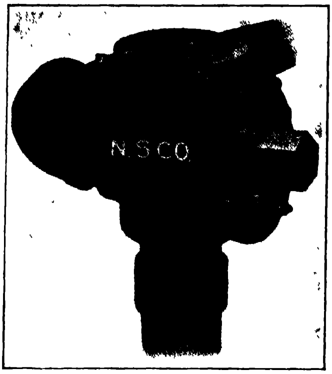


FIG. 161.—Control casing head.

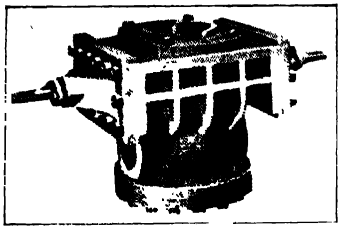


FIG. 162. Blow-out preventer.


FIG. 163.—Taylor-Liady packing spider.

The Blow-out Preventer.[2]—A device known as a "blow-out preventer" is widely used on rotary drilled wells to prevent the circulating fluid from being forced out of the hole when it is expected that high-pressure sands will be encountered. This is a special form of casing head which is screwed on top of the last string of casing landed or cemented in the well. It is equipped with a pair of sliding gates which close about the rotary drill stem and pack off the space between it and the well casing (see Fig. 162). The side outlets provide a means of connecting 6-in. pipe with the space between the casing and the drill stem. A gate valve provides the necessary control of each outlet. The gates are ordinarily kept open, but in the event of a threatened blow-out are closed about the drill pipe, preventing further escape of the well fluid. Each gate is controlled by a separate stem operating through a threaded nut and stuffing box, such as is used on an ordinary gate valve stem. An extension of the stem permits of operating the device from the outside of the derrick. A back-pressure valve in the drill stem prevents mud from blowing out through the stem, and with a blow-out preventer to pack off the space between the stem and the casing, the well is securely shut in until the pressure can be killed with mud, or until provision can be made for taking care of the flow. If cable tools are employed, the blow-out preventer can be used effectively in packing off the space between two strings of casing. In connection with a gate valve or control casing head on the inner casing, through the open gate of which the cable tools may be operated, ample security against blow-outs is afforded.

The packing spider illustrated in Fig. 163 serves to control the flow of gas and oil that sometimes occurs between two strings of pipe in the well.

The Oil Saver.—Various devices known as "oil savers" are available for closing in the top of an ordinary casing head in such a way as largely to prevent the escape of fluid under pressure about the well mouth, yet permitting free movement of the drilling cable. These are of two general types: first, one in which the cable works through a gland stuffed with hydraulic packing (see Figs. 164 and 166), and

secondly, one in which the cable is enclosed within a long, polished working barrel passing through a suitable stuffing box (see Fig. 165). The latter is similar in principle to the circulating head described in connection with the standard circulating system of drilling (see page 139). The ordinary forms of oil savers are simply held

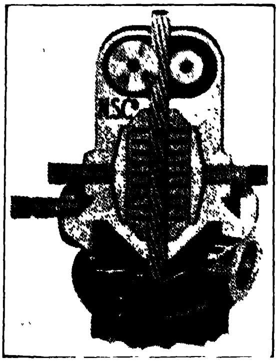


FIG. 164.—Oil saver, roller type.

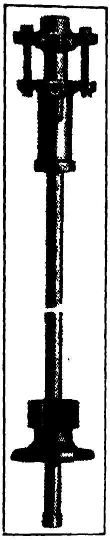


FIG. 165.—Oil saver, barrel type.

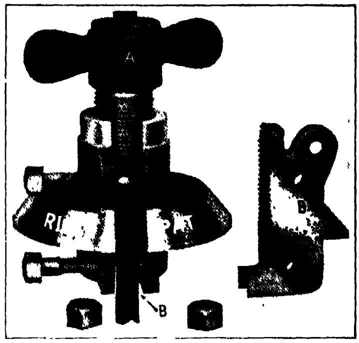


FIG. 166.—Rigby oil saver.

in position in the casing head by set screws, and are not absolutely secure against leakage if subjected to great pressures. They serve, however, to divert oil which may flow from the well while drilling is in process, through the side outlets of the casing head, into the lead lines connecting with the storage tanks or sumps.

Control of High Pressure by the Use of Mud-laden Fluid

In controlling high-pressure gas, the best plan is to deal with the menace at its source and prevent the gas from entering the well. This can ordinarily be accomplished with the aid of mud-laden fluid. We have seen that the opportunity afforded to use mud-laden fluid in sealing off and controlling high-pressure sands is one of the principal advantages of the modern hydraulic rotary and standard circulating methods of drilling.

The effect and manner of application of mud-laden fluids in ordinary drilling practice have already been adequately described (see page 172), but descriptions of certain special applications of the mudding process in controlling high pressures have been reserved for the present chapter.

If the well is being drilled by rotary methods and high-pressure gas is encountered, the circulating fluid is at once thickened by the addition of clay to the mud pit, drilling being discontinued for a time if necessary,

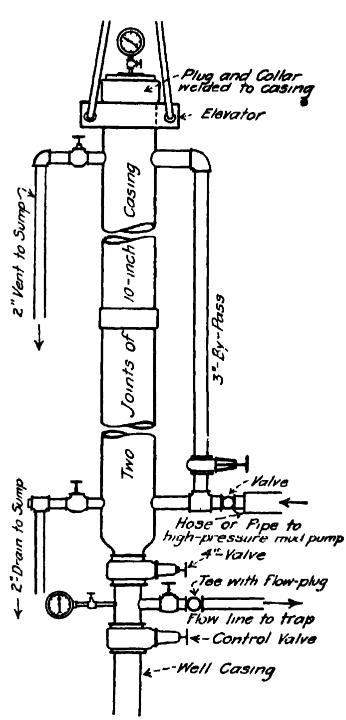
to allow ample opportunity for the mud to seal the pores of the high-pressure stratum. Every precaution must be taken to avoid a "blow-out," or ejection of the fluid from the hole. The ability of the circulating fluid to resist the gas pressure and prevent its admission to the well depends chiefly upon its hydrostatic head and density. Ordinarily about 15 per cent heavier than water, each hundred feet of mud fluid pressure is equivalent to about 50 lb. per square inch. This can be increased to as much as 60 lb. per square inch by addition of clay until the fluid has a density of 1.4. At a depth of 1,000 ft., the mud fluid may therefore exert a pressure of 600 lb. per square inch. If a gas sand encountered at this depth is under a greater pressure, obviously gas will enter the well; and unless additional pressure is applied or the outlet from the well is closed, the fluid will be violently ejected. In recent experiments in Louisiana,[7] iron oxide has been added to the well fluid to give it greater density in opposing high gas pressures. Mixtures weighing as much as 17 lb. per gallon (normal weight about 10 lb.) have been prepared and effectively used in some cases.

If gas enters and mixes with the circulating fluid, the density of the latter may be considerably reduced by gas occlusion, thus reducing the hydrostatic head on the well and the effectiveness of the mud in resisting the gas pressure. Fresh fluid should be circulated continually through the well and the mud should be agitated on reaching the surface to free it from occluded gas before again pumping it into the well. Blow-outs sometimes occur during removal of the drill stem from the well. Displacement of fluid by the stem results in considerable subsidence of the fluid level when the stem is withdrawn, with consequent decrease in the hydrostatic head opposing a high-pressure sand in the bottom. More fluid should be introduced at such times, or the mud should be thickened.

Mudding under Pressure.—If a high-pressure sand is suddenly encountered with rotary tools in the well and there has been insufficient time to thicken the mud fluid to resist it properly, at the first sign of instability of forces within the well the blow-out preventer is closed and drilling is discontinued. The mud in the slush pit is thickened by the addition of clay, until a mixture as thick as the pump will handle is obtained. As this thicker mixture is pumped into the well through the drill stem, the pressure builds up until a sufficient pump pressure is added to the natural hydrostatic head to offset the pressure in the sand. Excess pressure beyond this point forces the well fluid into the sand, and as the fluid is absorbed, the sand pores gradually become clogged with clay, until the openings by which the gas enters the well are closed. By this time the heavier mud will also have considerably increased the normal hydrostatic head so that the pump pressure can gradually be reduced, the blow-out preventer is cautiously opened and circulation is resumed. Slow drilling with frequent rest intervals for mudding under pressure will usually enable the tools to penetrate the high-pressure sand without loss of control.

Use of the "Lubricator."—If the drilling tools are out of the hole when a blow-out occurs and it is possible to close the outlet, either with the aid of a blow-out preventer or a control casing head or both, a somewhat different procedure must be

adopted. The problem now presented is that of placing more mud in the well so that greater hydrostatic resistance may be exerted by the well fluid. In order to accomplish this without releasing the pent up forces within the well, a device called a "lubricator" is rigged above the casing head.[5] This consists of two joints of casing about 10 in. in diameter, connected by a coupling with a tee at the bottom, which, in turn, is connected by a nipple to the top outlet of the control casing head or valve, *A*, (see Fig. 167). Near its upper end, the 10-in. casing connects through a reducer to a 2-in. pipe which, by means of two elbows and a nipple, is led down at one side of the 10-in. casing to about the level of the derrick floor, and thence to the mud pit. A control valve, *B*, is placed in this 2-in. line at some convenient point outside of the derrick. A 3-in. line connects the side outlet at the lower end of the 10-in. pipe with a high-pressure slush pump. All pipe and fittings should be capable of withstanding heavy pressures.



(*After H J Steiny, California State Mining Bureau, Dept of Oil and Gas*).

Fig. 167.—"Lubricator" for use in mudding high pressure wells.

With valve *A* closed and *B* open, a thick mud is prepared in the mud pit and pumped through the 10-in. casing until it overflows through the 2-in. line which returns the excess to the mud pit. The pump is then stopped, valve *B* is closed and *A* is opened. The mud in the lubricator, by reason of its excess of density over that of the well fluid, sinks through the casing to the bottom of the well. Valve *A* is then closed, *B* is opened and the process is repeated until the well fluid has been greatly increased in density and a considerable depth of thick mud has settled to the bottom of the well. Pump pressure may then be applied by closing valve *B*, opening *A*, and operating the pump, thus forcing the thickened fluid to flow into the high-pressure sand, depositing its clay in the sand pores about the walls of the well. After the formation ceases to absorb the well fluid under high pump pressure, the pump is stopped and valve *B* is cautiously opened. If the fluid is not ejected, it may be assumed that the high-pressure sand has been effectively sealed and the lubricator is removed and drilling continued.

If the cable tools are used, alternate drilling and mudding in this manner will make it possible to penetrate the high-pressure sand and continue to greater depths if desired; but care should be taken not to permit too low a fluid level on the sand, or the pressure may clear the sand pores of mud and cause a recurrence of the difficulty.

Use of the Circulating Head in Controlling High-pressure Wells with Mud-laden Fluid.—The circulating head and mud-pumping equipment described in connection with the standard-circulating system of drilling offers a convenient means of controlling high pressures in wells drilled with cable tools (see page 305). If the presence of a high-pressure sand is known or expected, the circulating head should be placed on the casing before penetrating it. In this device, the space about the drilling cable within the head is packed off with a stuffing box. If high-pressure gas is encountered, heavy mud is pumped through the side outlets of the head, and

pump pressure is maintained until the sand is sealed. If cable drilling is in progress and an unexpected flow of high-pressure gas is encountered, the pressure may be brought under control with the aid of a lubricator and a circulating head is placed on the casing to take care of further mudding before drilling is resumed.

Placing Mud-laden Fluid in a Well That Cannot be Shut In.[5]—It will occasionally happen that a well cannot be shut in, either because the casing has not been landed and gas finds its way to the surface outside of the casing, or because it would be unsafe to subject the casing and fittings to the prevailing pressure. In such a case it would be impossible to use the lubricator in the manner described above and another method of introducing the fluid must be adopted.

Often there will be a conductor string landed at some point above the high-pressure sand, on which a tee casing head may be placed. A string of 2- or 3-in. tubing is lowered to bottom through the top opening of the tee, and the space around it is packed off so that it is secure against gas pressure. The lower end of the tubing is equipped with a back-pressure valve or a loosely placed wooden plug which can be forced out by pump pressure, while the side outlet of the tee is controlled by a gate valve. Mud is pumped down through the tubing to the bottom of the well, the gate valve being partially closed to prevent it from being blown out by the gas pressure, until there is sufficient mud within the well to offset the pressure. The outlet may then be closed and pump pressure applied to force fluid into the sand.

If the gas pressure is not too high, mud may be introduced by setting the casing on bottom after the high-pressure sand has been penetrated, filling the casing with mud; and then lifting it slightly so that the mud rapidly rises in the space about the casing, inundating the gas sand. By this procedure, the well is usually filled to a point between two-thirds and three-fourths of its depth, and the height of fluid is in many cases sufficient to offset the gas pressure. Unless there is a large clearance between the walls of the well and the casing, there is danger of the casing becoming frozen when this method is used, and in some instances collapse of the casing has resulted.

It may seem desirable or necessary at times to introduce mud-laden fluid at the surface into the space around the outside of the casing, or between two strings of casing.[9] This should be avoided, however, if possible, since in flowing down the walls of the well the fluid often loosens much coarse material which settles about the collars and freezes the pipe.

Capping a Flowing Well

If a blow-out occurs and no control devices have been provided at the casing head, the well may get so far out of control that the flow of mud, oil and gas makes it difficult to attach a control head or valve on the casing. Since the well will continue to flow with great loss of oil and gas until checked in some way, it is necessary to at once undertake "capping" operations. This involves placing a valve of some sort on the outlet.

The valve to be employed is of the flanged gate type, and should be of massive construction to withstand the high closed-in pressure to which it is likely to be subjected (see Fig. 168). This "master valve" is suspended over the mouth of the well in the derrick and is gradually lowered on a previously placed flanged connection on the casing, while the stream of gas and oil passes through the open gate (see Fig. 169). When the flanges have been bolted together, the gate is slowly closed until the well

is brought under control. A similar, valve is then connected above the master valve with suitable connections, the second valve being intended for use as the working control valve, while the lower master valve is normally left open. In this way most of the wear, which may become serious if sand flows from the well with the oil, falls upon the upper valve, and the lower is kept in good condition for use in controlling the well when the upper valve is being repaired or replaced.

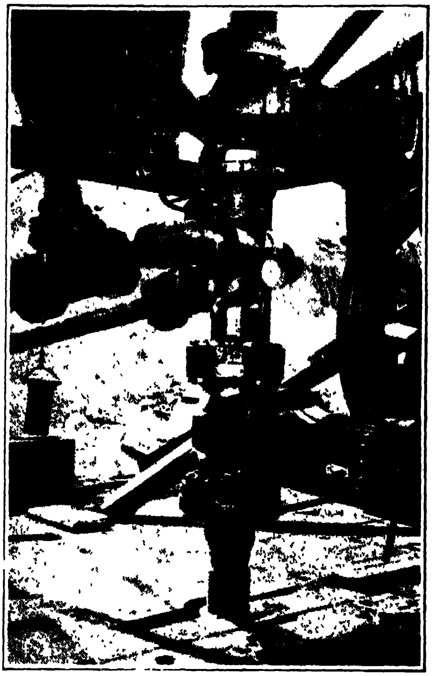


FIG. 168.—Control valves on a high-pressure well.

Often the valve controls on a high-pressure oil or gas well will be arranged in the form of a cross on a four-way tee, with two additional gate valves on the side outlets, which control the flow through the lead lines. The upper valve in this case serves merely as an additional control at such times as it may be necessary to allow the well to blow, or to permit excess oil, beyond what can be taken care of by the side outlets, to escape. In the case of exceedingly high pressures it may be unsafe to shut in the well completely.

The scouring effect of sand carried by the oil may necessitate frequent replacement of valve parts and connecting fittings. It has been found helpful, in reducing damage due to the cutting action of sand, to place short extensions in the direction of primary flow, at each change in direction. That is, instead of using elbows, a tee will be placed at each bend, and a short-capped nipple inserted in the extra outlet of the tee. The space within this nipple cushions the flow, much of the sand eddying into the extension nipple, to be eventually diverted at reduced velocity into the main stream of fluid through the side outlet. This principle is adapted in the design of certain valves used in handling oil containing sand.

Anchoring Casing and Control Valves.—The upward pressure exerted by gas enclosed within the casing by closing the outlet is in some cases great enough to place considerable strain upon the connections at the casing head. In some instances pressures have been sufficient to lift the casing bodily out of the well. Suppose, for example, that 10-in.,

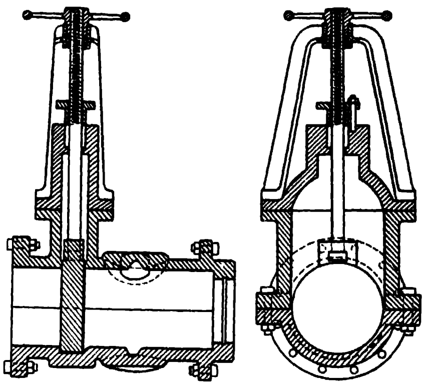
40-lb. casing is in use, and that a gas sand under a pressure of 1200 lb. per sq. in. is encountered at a depth of 1,500 ft. The upward pressure exerted on the cross-sectional area of the casing head or control valve will be $78.54 \times 1{,}200 = 94{,}248$ lb. The weight of the column of casing will be about 34,000 lb. less than this, and unless friction on the walls of the well prevents, the casing will be forced out of the hole. To offset

FIG. 169.—Capping a gusher.

this tendency, it is customary to anchor the control valves or casing head to the derrick sills with the aid of a heavy steel clamp and long bolts. In order to give additional security, some operators construct a heavy block of concrete about the casing below the derrick floor, embedding the anchor bolts in the concrete in such a way as to prevent the pipe from moving.

The Mortenson Well Capping Device.—In the case of gushers producing large quantities of oil and gas under high pressure, it may be difficult or impossible to attach an ordinary gate valve or control casing head in the manner described above. The great force of the flow sometimes makes the open end of the casing practically inaccessible. Or perhaps, the upper end of the casing has become damaged, or is not suitably equipped to receive and support a heavy control valve. Under such conditions, recourse may be had to the use of a Mortenson "capper" (see Fig. 170).[2] This is a massive gate valve built in sections, in such a way that it may be assembled about the column of casing without the necessity of making any screw connections, or of lowering the valve through the flowing gas and oil. The capper is divided into two parts longitudinally, and is bolted about the upper end of the casing with the shoulder at the lower end, just below the top coupling. The gate is withdrawn into its recess while the device is being placed on the casing, so that it in no way obstructs the flow of oil or gas. If desired, it can be placed one joint below the upper end of the column with the upper joint of casing extending up through the valve, the upper joint being detached after the capper is in position. A groove in the

lower end of the device provides a recess for hydraulic packing which bears against the pipe below the coupling and prevents leakage. Two circular side openings provide a means of attaching lead lines which are controlled by separate gate valves. The upper end of the capper is equipped with a flange and bolts for pipe connections, while a flange at the lower end provides a means of attaching anchor bolts the lower ends of which are embedded in a block of concrete cast about the casing. The lower edge of the groove into which the gate fits is rounded in order to permit sand to be squeezed out of the groove as the gate is seated. The device is manufactured in several different sizes, varying in weight from 1,600 lb. for 6¼-in. casing, to 3,600 lb. for 15½-in. casing.



(*After Arnold and Garfias in U. S B. Mines Tech. Paper 42*).

FIG. 170.—Mortenson capping valve for controlling high-pressure wells.

PROTECTION OF WORKMEN ABOUT HIGH-PRESSURE WELLS

It is obvious that considerable risk is attached to the conduct of work about high-pressure wells, and every precaution should be taken against accident. Excessive pressure may result in the failure of control valves or fittings about the casing head, which are shattered with explosive violence. A sudden rush of high-pressure gas, accompanied by mud or oil, may wreck the derrick or force the drill stem or casings out of the well. The position of the derrick man in such an event is particularly dangerous. A safety device in the form of a wire rope sling which enables the derrick man to slide down one of the guy wires to safety, has been rather widely adopted in some of the California fields. The stems controlling blow-out preventers and control heads should be so extended that they may be adjusted in case of necessity from a point outside of the derrick.

Capping operations must often be conducted in the presence of large quantities of highly inflammable oil and gas, ready to explode or flash into flame on the slightest provocation. While natural gas is not poisonous or asphyxiating unless hydrogen sulphide is present, the mere absence of oxygen in an atmosphere so laden with methane and oil vapor may make work about the well difficult and even dangerous. The use of self-contained oxygen breathing apparatus about oil and gas wells under such conditions offers a possible solution for this difficulty. Every precaution must be taken against fire.

PREVENTION AND CONTROL OF OIL AND GAS WELL FIRES

The destruction wrought by the firing of a well producing large quantities of oil and gas under high pressure has been demonstrated in many

fields. Aside from great losses of oil and gas from the burning of the well itself, the danger to other near-by wells and surrounding property usually requires prompt action in controlling and extinguishing it. The conditions attending such a conflagration present a problem in control of natural forces very difficult of solution. The column of flame may extend for several hundred feet into the air above the casing head (see

FIG. 171.—Lakeview No. 2 gusher, Sunset Field, California.

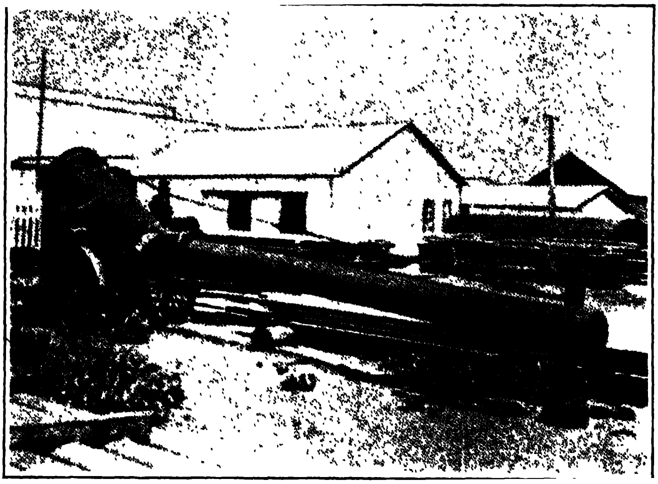
FIG. 172.—A gusher fire, Elk Hills Field, California.

Fig. 172). If the well produces more oil than the flames can consume while in the air, the surrounding terrain may be deluged with burning oil. The derrick and wooden portions of the drilling plant are rapidly consumed, and the metal portions are converted into a mass of twisted iron and steel. This and the intense heat prevent close approach to the casing head. The casings projecting from the well mouth are often so damaged that they offer little opportunity for shutting in the flow even though means of approach and control for the fire are possible.

Gas well fires are easier to extinguish than oil well fires, for the reason that the gas is completely consumed and the flame is confined to a well-defined column of no great thickness. The force of the flowing gas and scarcity of oxygen, except about the periphery of the ascending stream, usually prevent the gas from burning until it is well above the outlet.

As the column ascends, however, air is drawn in and mixed with the gas so that it burns freely.

If the gas flow can be momentarily interrupted, it will usually be extinguished. It is customary to resort to the use of steam to accomplish this. A large volume of steam suddenly and forcibly applied immediately above the casing head, against the stream of gas, cuts off the supply of oxygen necessary to support combustion and smothers the flame. Incidentally, the steam serves to cool the ascending vapors and metal objects about the well and casing head.

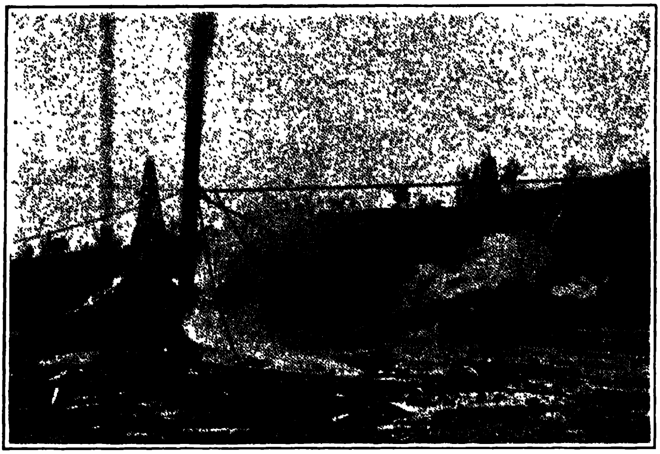


(*After C. P. Bowie in U. S. B. Mines Bull.* 170).
FIG. 173.— Portable gas well fire extinguisher.

In combating gas well fires with steam, a battery of portable boilers—frequently 20 or more—of the type used in furnishing power for drilling operations, is assembled about the well at a safe distance. Steam pipes equipped with goosenecks terminating in flattened nozzles are connected with the boilers, pushed forward toward the fire and adjusted so that the nozzles will direct their jets of steam directly against the outlet of the casing head. The boilers are fired and a supply of high-pressure steam is suddenly discharged into the fire from all sides, and, if possible, maintained for several minutes after the fire is extinguished. Sprays of water similarly directed are sometimes successful, the water being converted into a blanket of steam on contact with the flame. A 40,000,000-cu. ft. gas well fire near Monroe, La., was successfully extinguished by this method.

Another method commonly employed in extinguishing gas well fires involves the lowering of a large diameter pipe in a vertical position over the well, in such a way as to enclose the burning column of gas. The pipe serves to prevent admixture of air with the gas until it has passed through the pipe, the flame being confined to the gas above the upper end. The pipe is simply allowed to topple over, throwing the flame to one side of and to a safe distance from the well. Fig. 173 illustrates a small portable extinguisher operating on this principle, that is used by the Empire Gas and Fuel Company in combating small gas fires.[10] The hood which is lowered over the casing head is in this case mounted on wheels, and supports about 20 ft.

of 14-in. pipe. When the device is in position over a burning well, a valve or damper in the upper end of the hood cuts off the supply of gas to the fire, directing it through a side outlet connecting with a 10-in. pipe, which carries the gas to a safe distance from the fire. The same principle has been applied with larger and more cumbersome apparatus in controlling large fires. In one case it was found possible to suspend a cableway over a gas well fire from elevated ground on either side, on which a 36-in. smokestack riveted to a funnel-shaped hood was transported to a point over the fire and lowered over the casing head (see Fig. 174). When the flame had passed to the top of the stack, the ground and metal parts about the well were thoroughly cooled with water, the top of the stack was drawn over at a considerable angle, and the base quickly removed from the well, thus cutting off the supply of gas through the stack and extinguishing the fire.



(*After C P Bowie in U. S B Mines Bull* 170)

FIG. 174.—Placing a 36-inch smoke stack over a burning gas well.

A method of successfully combating gas well fires involving the use of explosives has recently been developed in California. A fire well in the Elk Hills field had defied efforts to extinguish it with steam and carbon tetrachloride, when the use of explosives was suggested. Wooden towers erected on two opposite sides of the well provided a means of stretching a cable a few feet from one side of the column of flame, which extended 200 ft. into the air above the casing head. A small carriage was rigged, suspended on two flanged pulleys traveling on the cable, and a second pull rope provided a means of moving the carriage along the cable. A charge of 150 lb. of blasting gelatin was suspended from the carriage and the latter moved along the cable until it reached a position near the column of flame. The explosive was then detonated electrically. Observers state that the flame was literally blown out by the force of the explosion, the upper part of the column being blown upward, the lower part downward and the central portion horizontally away from the position of the explosive. A battery of boilers were fired and the steam, with about 100 bbl. of carbon tetrachloride, was brought to bear upon the base of the fire at the time of the explosion. This particular well ranks as one of the world's largest gas wells, the flow being in excess of 100,000,000 cu. ft. at the time of the fire. It was ignited by friction of the gas, carrying large quantities of shale and sand, upon the 6-in.

flow line through which the gas was ejected from the well. Explosives were later successfully used in a somewhat similar manner in extinguishing several oil and gas fires in the Long Beach field of southern California.

Oil Well Fires.—In the case of an oil well fire, the flame is not usually confined to a well-defined column, as in the case of gas. Burning oil falls all about the well, so that the source of the fire is more difficult of approach. The casing head and metal parts of the rig become heated so that they often reignite the oil after it has been extinguished, unless it can be kept under control for a sufficient time for surrounding objects to cool.

Many spectacular oil well fires have been experienced in the American fields, and published accounts of them provide interesting reading and describe many ingenious methods used in extinguishing and controlling them.[10] The methods employed necessarily vary with the size of the fire and the surrounding conditions. Steam is customarily employed, as described above, but in the case of certain large fires has been unsuccessful. In one instance, a 1,000-bbl. well became ignited, and due to lateral deflection of the stream of oil as a result of collapse of the casing head, a crater 50 ft. in diameter and 40 ft. deep was formed about the well. A large number of boilers were set up near the well and steam and water applied in the usual way. Though the fire was repeatedly extinguished, the heated walls of the crater reignited it as soon as the blanket of steam cleared. This fire was eventually extinguished by flooding the crater with mud, mixed in a large reservoir specially constructed near by. Steam formed from the mud extinguished the fire and the mud plastered and cooled the walls of the crater.

In another case of a fire well producing 48,000 bbl. of oil daily, it was found impossible to extinguish the flame with 36 boilers. A circular levee 3 ft. high and 200 ft. in diameter was constructed about the well to confine the burning oil, and a 328-ft. tunnel was driven to intersect the well casing at a depth of 18 ft. below the surface. The well contained three strings of casing: 10, 8 and 6 in. A split clamp was placed around the 10-in. casing, and to this was attached a 6-in. pipe extending beyond the portal of the tunnel (see Fig. 175). An especially constructed bit made from a case-hardened nipple was screwed on the end of a line of 4-in. pipe extending through the 6-in. line, and equipped at its outer end with a cap and sprocket wheel to which was attached a rotary chain drive. A screw jack set against a post served to force the bit against the pipe as the 4-in. line revolved. Rotating the 4-in. pipe and bit caused the latter to cut a hole through all three casings, care being taken to stop the bit in the center of the 6-in. casing. A hole previously cut in the bit was turned so that asbestos shavings pumped under pressure through the 4-in. pipe were forced down into the stream of ascending oil and accumulated about the bit, closing the small spaces about the bit and cutting off the supply of oil to the surface.

The work of combating oil fires is hazardous and difficult. The temperatures to which workmen are exposed are extreme. Such work as adjusting steam lines and nozzles and making preliminary arrangements requires that the workmen approach as nearly as possible to the well. At such times they may be partially protected by sheet metal or asbestos shields pushed ahead of them as they advance. It may be necessary to continually spray the workmen with water to prevent ignition of clothing.

CHAPTER XI

FINISHING THE WELL

On encountering an oil or gas stratum which gives evidence of being commercially productive, the driller proceeds carefully and cautiously. Perhaps the stratum is under high pressure, and unless precautions are taken there is danger of a "blow-out" which may be accompanied by an uncontrollable flow of oil and gas. Reduction of the specific gravity of the mud-laden fluid by contamination with occluded oil and gas will sometimes be responsible for a blow-out in rotary drilling. Such an event usually results in great loss of oil and gas, and often seriously damages the well and its equipment. If the producing stratum is an unconsolidated sand, the well may "drill itself in" as soon as the cap rock is penetrated, large quantities of sand flowing to the surface with the oil and gas and forming a cavity in the oil sand about the well.

If the oil sand is under low pressure, there may be very little evidence of the presence of oil during the ordinary processes of drilling. A high fluid level within the well may prevent any oil or gas from escaping from the sand. If the rotary method of drilling is employed, the sand faces soon become rapidly mudded so that their true character is obscured. The circulating fluid may so thoroughly wash the cuttings from the drill that little evidence of the presence of oil remains. To the trained eye of the driller, however, there will usually be evidence that at least leads him to suspect the presence of oil. Perhaps a little oil sand clinging to the drilling bit or the bailer, or a few globules of oil or gas froth on the mud ditch will tell the story. If there is evidence of oil and the rotary equipment is in use, the clay content of the circulating fluid should be at once reduced by adding water to the fluid in the mud pit. A core of the material in the bottom, taken with a suitable core barrel, will give positive evidence. If the cable tools are used, the bailer will usually bring up samples of the material in the bottom that have not been greatly disturbed. A chloroform test will be decisive if there is any doubt of the presence of oil.

While we may depend upon such indications and tests for qualitative evidence, it is often difficult to form any estimate of the probable productivity of the well without making an actual pumping test. The well is "bailed down" to remove the hydrostatic head on the oil stratum and allow the oil and gas to escape from the sand. This is done cautiously in order to avoid a sudden flow which might be difficult to control. As

the hydrostatic head is gradually reduced by continued bailing, oil will begin to enter as soon as the balance of pressure is in its favor, and will float to the top of the fluid in the well, increasing in quantity as the head is reduced. If the productive sand is unconsolidated, it may tend to "heave" or flow into the well with the oil, occasionally filling the hole for hundreds of feet above bottom and necessitating prolonged bailing or even redrilling. If there seems to be danger of this, care should be taken not to bail the well down too rapidly or too far, and the bailer should be lowered to bottom for its load in order to observe the tendency of the sand to enter.

In the case of reservoir rocks of limestone or "tight" sands or shales, it is usually necessary to make an actual pumping test for a few days before the full productivity may be realized. In hard, close-grained rocks such as the limestones, it is also customary to "shoot" the wells in the hope of fracturing the oil stratum so that oil may freely enter. Rush of air from the well as a result of a shot of nitroglycerin or dynamite often causes a flow of oil which sometimes lasts for several days or weeks, though the well may have given little evidence of the presence of oil prior to blasting.

It will be noted that the manner in which oil makes its presence known as the drill enters the oil stratum varies markedly, depending upon the nature of the reservoir rock and the pressure under which it is stored. The method of drilling employed also has its influence in determining in some measure the hydrostatic head resisting entrance of the oil. In high-pressure territory, there will be no uncertainty, and flowing wells or gushers, in which the oil is thrown from the well mouth high into the air, occasionally offer new problems in control of exceedingly destructive forces. In the case of low-pressure strata or close-grained rocks, on the other hand, the skill and ingenuity of the driller may be taxed to the utmost to establish conditions within the well which will cause it to yield oil in commercial amounts.

Setting the Oil String or Liner.—Drilling should be continued until the oil stratum is penetrated, and unless bottom water is encountered immediately below, the hole should be drilled for an additional 10 or 20 ft. This serves as a sump for the accumulation of sediment or cavings from the walls, or for sand which may enter with the oil, and also as a reservoir in which oil may accumulate. It is important that sand entering with the oil should not accumulate within the well opposite the producing sand, since it has a detrimental effect on production.

If the walls are firm and do not tend to cave, the well may be completed without casing of any sort opposite the productive stratum. This practice is characteristic in most of the fields of the eastern United States. The last string of casing or the "oil string," so named because it is the only one in contact with the oil, is in this case carried to a point

immediately above the oil stratum and set on a firm shoulder of rock in such a way as to exclude water and cavings from above.

If the productive stratum is a loosely cemented sand or sandstone, as is generally the case in the fields of California, Louisiana and southern Texas, it is necessary to carry the oil string through the oil sand to the bottom of the well. And in order that the oil may gain admittance to the pumping device which is placed within the casing, the pipe is perforated opposite the oil sand with numerous round holes or slots. These openings are frequently equipped with screens of various types which allow the oil to pass but exclude the sand which tends to flow in with the oil. The lower end of the oil string rests on bottom and should be securely plugged to prevent water or heaving sand from entering from below.

Perforating the Oil String

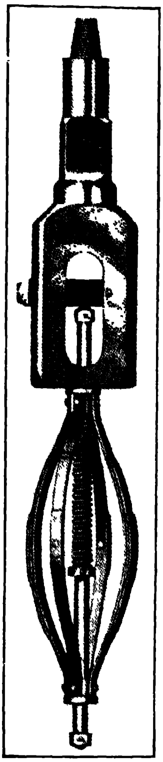
The oil string may be either perforated in the shop by drilling holes or cutting slots in it before it is placed in the well, or it may be perforated in the well with the aid of a casing perforator.* Shop-perforated pipe is preferable since the holes are more uniformly spaced, the openings are clean cut, and the casing is left in better condition than when it is perforated in the well. Furthermore, the operation of the perforator is always somewhat uncertain. However, it is sometimes unsafe, because of tendency of the walls to cave, to remove a string of casing from the well to insert shop-perforated pipe. In such a case, reliance must be placed on the successful operation of a casing perforator.

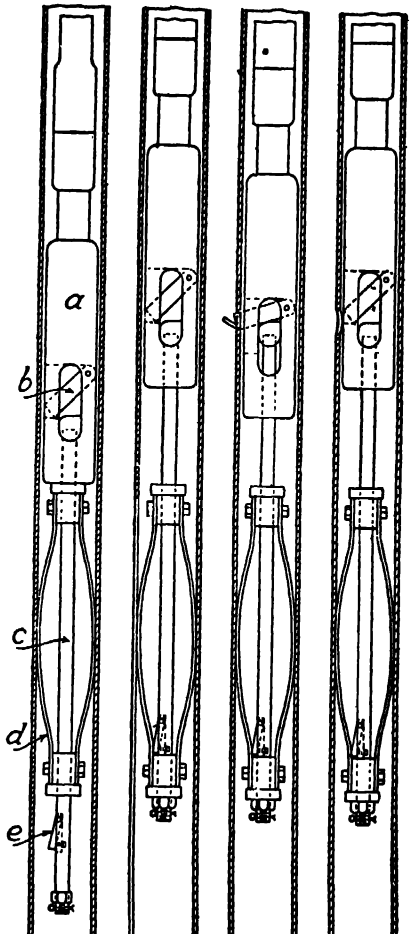
Perforating casing in the well is accomplished with the aid of one or another of the various forms of casing perforators of which there are two principal types: first, the single-knife perforator similar in many respects to a casing ripper; and second, the wheel-knife perforator equipped with one, or sometimes two, star-shaped wheels the points of which, when brought to bear against the inside of the pipe, cut slots in it.[4]

The single-knife perforator consists of a substantial frame or body, *a*, in which a steel knife, *b*, pivoted at one end, is mounted (see Fig. 176). The knife is actuated by a mandrel, *c*, which is free to move up and down in a slot cut through the body of the tool below the knife. A spring, *d*, presses firmly against the inside of the pipe. The spring is free to move up and down on the mandrel, except when engaged by the latch *e*. The tool is lowered on tubing to the depth at which it is desired to perforate the casing, and then pulled up a short distance. The spring, *d*, pressed tightly against the casing will drag, so that the mandrel, *c*, will be pulled up through the spring until the latch, *e*, is engaged. The tubing is then again lowered, the spring remains stationary because of its pressure against the pipe, continued descent of the tubing causing the knife to force its way through the pipe. The tool is then raised a short distance, allowing the knife to drop back into position to cut another perforation. By carefully

* Wagy, E. W., Perforated casing and screen pipe in oil wells, *Thesis*, University of California, 1920, later published as U. S. Bureau of Mines, *Tech. Paper* 247.

measuring the movement of the tubing on which the perforator is suspended, the holes punched can be uniformly spaced at any desired distance. By rotating the tubing through 90 or 180 deg., two or four rows of perforations can be cut around the circumference of the pipe. The shape of the knife controls the form and size of the perforation. The tubing is sometimes filled with water in very shallow wells, to add weight; or a string of fishing tools may be rigged and the perforator driven down with the jars.



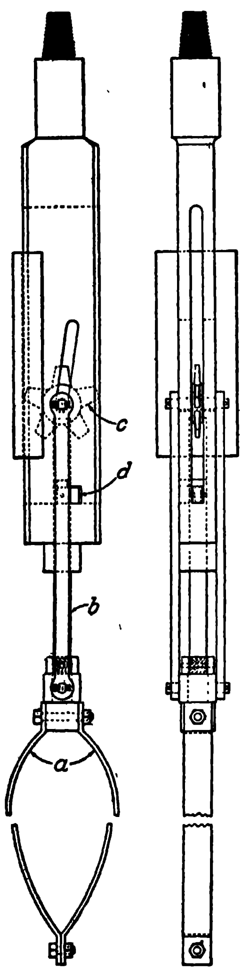


(*After P. M Paine and E W. Wagy*).

FIG. 176.—Casing perforator. FIG. 177.—Illustrating action of single-knife perforator. *a*, body; *b*, knife; *c*, mandrel; *d*, spring; *e*, lug.

Wheel-knife Perforators.—A number of well-known and commonly used casing perforators are in this group, notably, the Hardison, Star, Brinkman, Mack and Basch perforators. The first three mentioned are equipped with one wheel knife, cutting one row of perforations at a time, while the latter two are equipped with two wheels and cut two rows 180 deg. apart, with each application. A four-knife perforator is also available on the market, which punches four rows of holes 90 deg. apart, but it is said to be unduly complicated in its mechanism and to lack rigidity.

The Star Perforator will be briefly described as typical of the group of wheel-knife machines. It is operated on tubing and depends upon a spring, *a*, and mandrel, *b*, for setting the knife, *c*, which is shaped like a five-pointed star (see Fig. 178). A lug, *d*, on the mandrel prevents the knife from moving out of its position within the body of the tool while it is being lowered into position, but when the depth is reached at which it is desired to begin perforating, turning the tubing releases the lug from its recess. Further lowering of the tool forces the mandrel upward, pressure of the spring on the end of the mandrel holding the latter stationary as the tool is lowered. As the body of the tool is lowered over the mandrel, the wheel knife mounted on the upper end of the mandrel is forced up the inclined slot until the points bear against the pipe. Further downward pressure on the tool causes the knife to revolve, punching a hole as each point of the knife is forced against the pipe. After one vertical row of holes is cut in this way, the tool is raised to its original position, turned through 90 or 180 deg., and again forced downward.



(*After E. W. Wagy in U. S. B. Mines Tech. Paper* 247)

FIG. 178.—"Star" perforator.

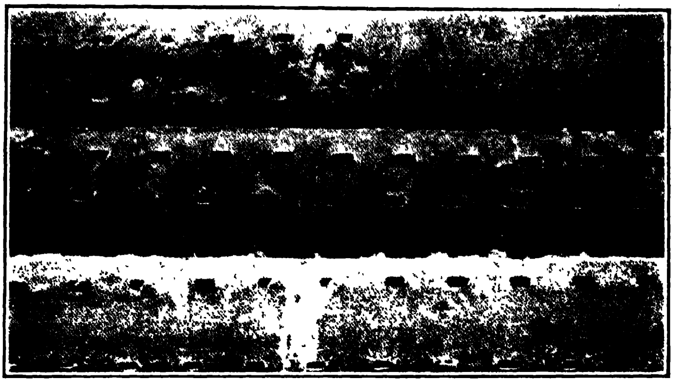
a, spring; *b*, mandrel; *c*, knife; *d*, lug.

The shape of the cutting points of the wheel knife can be varied to produce any desired form or size of slot (see Fig. 179). The size of the wheel and the number of points on it determine the spacing of slots. Single-knife wheel perforators can be adapted to different sizes of pipe by the use of adjustable backs, such as that indicated in Fig. 178. Double-knife perforators, which cut two rows of perforations at once, must be designed for the particular size of pipe in which they are to be used. Doubleknife perforators have a tendency to flatten the casing if used on thin-walled pipe, as a result of the strain exerted on two opposite sides simultaneously.

Casing perforators must be rugged, since the duty imposed is very severe, and they should contain as few working parts as possible. In long strings of heavy casing, where the walls to be perforated are thick and there is more or less spring in the pipe and tubing, the perforator must be worked alternately up and down against the pipe for each hole cut. This is accomplished, if the cable tool equipment is in use, with the aid of a jerk line from the wristpin, a connection such as is used in spudding operations. Two-way perforators are run below a fishing string on the drilling cable, and are driven down with the jars. Manipulation of a casing perforator on a string of tubing is more satisfactory than on a drilling cable, since the operator is better able to control the position of the holes punched. A single-knife machine cannot be satisfactorily operated on a drilling cable.

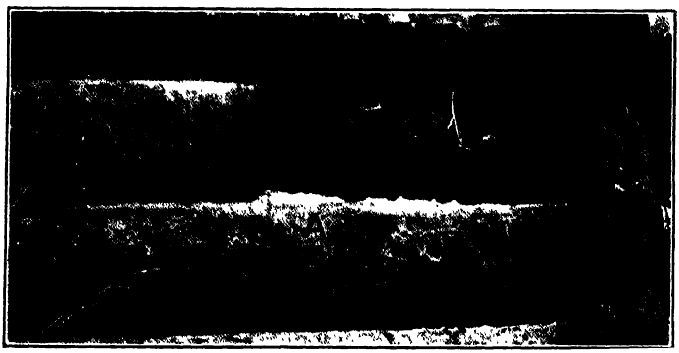
The perforator should be tested in a joint of casing before the tool is lowered into the well. Even when the machine is known to be in good condition, however, there will be some uncertainty in its action due to slight differences in diameter of the pipe, or thickness and hardness of the metal walls. All of the perforating should be done if possible without removing the perforator from the well; otherwise, there is danger during a second application, of the second series of perforations encountering the first, causing local fracturing or

tearing of the metal, and greatly weakening the pipe (see Fig. 180). Care must be taken not to cut too near a coupling. If a hole is punched through a coupling, there is danger of the pipe parting or collapsing. An accurate casing record is essential in determining at what depths to perforate.



(*After E W. Wagy in U S B Mines Tech. Paper* 247).
FIG. 179.— Pipe perforated in the well with Star type of perforator.
A, imperfect and *B*, properly cut perforations.

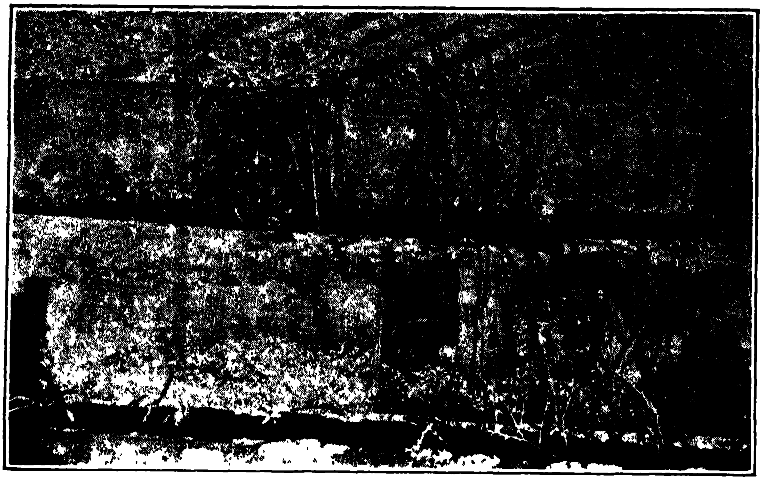
While most manufacturers of casing perforators contend that their machines are universally positive and reliable in action, some of the best types occasionally fail to accomplish their intended purpose. In some instances, casings drawn from wells have been found to have been merely dented by the perforating machine, or only



(*After E W Wagy in U S B Mines Tech. Paper* 247)
FIG. 180.— Casing damaged by double application of perforator (see pipe marked *A*).

partially perforated. Operators have thus been led to believe that their wells were small producers or barren, whereas if the casing had been properly perforated they would have been good producers. Perforators are also occasionally responsible for ripping or splitting of the casing, a series of misplaced perforations sometimes so weakening the pipe that it collapses or parts in the well.

Shop perforated pipe is usually prepared in the shop with the aid of the drill press, boring round holes which may range from ⅜ in. to ¾ in. in diameter, depending upon the nature of the oil sand and the type of screen to be used. The holes are bored in longitudinal rows, 30, 45, or 60 deg. apart on the circumference of the pipe (*i.e.* 6, 9 or 12 rows), with the holes 4 or 6 in. apart and staggered in alternate rows (see Fig. 181). The



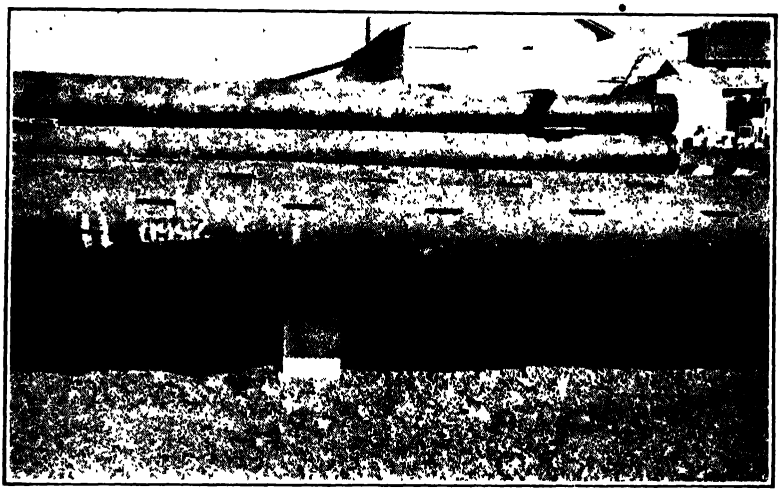
(*After E. W. Wagy in U. S. B. Mines Tech Paper* 247).
FIG. 181.—Shop perforated, screen-wrapped pipe, showing clogging of screens after removal from well.

rows of holes extend over a length of pipe equivalent to the thickness of the oil sand. The number of holes and their spacing will depend upon the size of the pipe, care being taken to avoid undue weakening of the metal so that there is danger of it parting or collapsing in the well.

Liners or oil strings are sometimes made up of oxyacetylene welded pipe, and inserted joint casing is also occasionally used. The projecting collars of ordinary collared joint casing are often particularly troublesome in unconsolidated sands containing oil. Nevertheless, this latter type of casing is generally preferred to the inserted joint because of its greater strength. Inserted joint casing must be perforated in the shop, since it is too weak to withstand the action of a perforating machine in the well.

Some operators prefer a slot-shaped opening to the round holes formed by the twist drill, claiming that the former allows less sand to pass than the latter. Slots may be cut with a planer or shaper, or with the oxyacetylene torch. Drops of molten metal forming on the inside of the pipe as a result of the use of the torch are sometimes detrimental to swabbing and other like operations. Narrow slots are usually preferred, but it is scarcely practicable to cut them less than ⅛ in. wide, and they

are occasionally as wide as ½ in. The length of the slots is usually 2 or 3 in., and they are aligned in rows with the longer dimensions parallel with the axis of the pipe (see Fig. 182). The Layne and Bowler shutter pipe* and the "Emsco"† screen pipe are varieties of slotted pipe in which the slots are punched or cut with special tools in the shop. The slots are in this case horizontal. Punching slots in this way causes



(*After E. W. Wagy in U. S. B. Mines Tech. Paper* 247).
FIG. 182.—Slotted pipe.

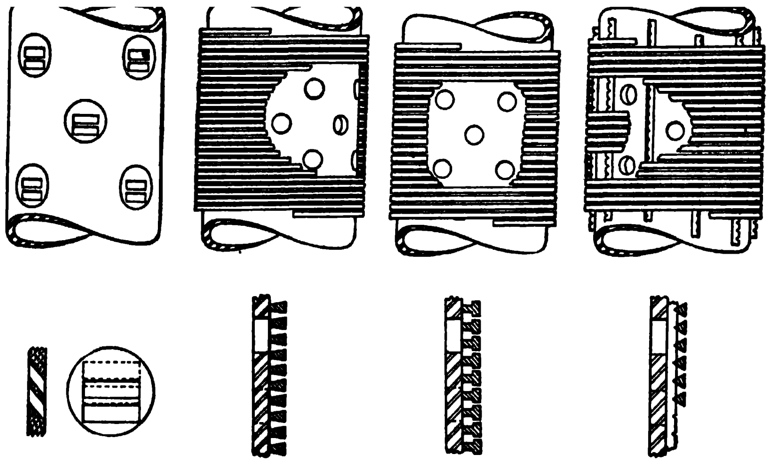
considerable bulging of the pipe, but the manufacturers claim that the shutter opening, which is inclined upward, is more effective in excluding running sands.

Screens used on perforated pipe are of two general types: first, a variety made by wrapping closely spaced coils of wire about the pipe over the perforations, and second, the so-called button screen, in which the screen is cast in a small metal disc which is either pressed and swaged or screwed into a circular perforation. The button type represents a more recent development, and in the California fields has largely displaced the wire-wrapped type of screen.[4]

In the construction of the wire-wrapped type of screen, the perforated pipe is placed in a lathe and the wire wrapped on as the pipe revolves. The size of wire to select and the spacing of coils depend upon the size of sand particles to be excluded and the gravity of the oil. Round wire was formerly used, but inasmuch as coils of round wire form wedge-shaped spaces which are readily clogged by accumulated sand, efforts have been made to design screens of angular wires, so placed that a smooth

* Manufactured by Layne & Bowler Co., Los Angeles, Cal.
† Manufactured by E. M. Smith Co., Los Angeles.

exterior surface is presented with the smallest screen opening on the outer surface. This insures any sand grain that can penetrate the outer opening a free passage through the screen and prevents clogging. Patented screens using wire of angular cross-section are illustrated in Fig. 183.



(a) (b) (c) (d)

(*After E. W Wagy in U S B Mines Tech Paper* 247).

FIG. 183.—Types of screen pipe.

a, Layne and Bowler button type with shutter openings, *b*, Layne and Bowler keystone wire-wrapped screen; *c*, Getty screen; *d*, Stancliff screen.

Two well-known types of button screen are widely used in the California fields: the McEvoy screen and the Layne and Bowler* screen. The McEvoy† button is screened with four thin strips of flat-surfaced metal, forming slots which parallel the axis of the pipe (see Fig. 184). The discs, which are of brass, are inserted in the pipe perforations under a pressure of 1,000 lb. per square inch, and are held in place by swaging the outer edge of each hole against a shoulder on the disc. The manufacturers claim that the vertical openings, which are flush with the outer surface of the pipe, do not become damaged or clogged by contact with the walls of the well while the pipe is being lowered into position. The Layne and Bowler screen is equipped with brass discs about 1½ in. in diameter, which are screwed into holes drilled and tapped in the casing at intervals of about 6 in. The discs are of the same thickness as the pipe, and are flush with the inner and outer surfaces when screwed into position. Two forms of screen openings are available in the Layne and Bowler button: the keystone form (similar to that illustrated in Fig. 184) and a "shutter" slot inclined upwards. The slots are in this case horizontal (see Fig. 183).

* Manufactured by Layne & Bowler Co., Los Angeles, Cal.

† Manufactured by McEvoy Wireless Strainer Co., Los Angeles, Cal.

There has been considerable discussion and experimentation in attempting to determine the best size and form of screen opening. The shutter form is apparently correct in principle if the sand tends to enter simply by caving or falling about the pipe. The angle of repose of the sand and the thickness of the metal forming the slotted openings would determine the effectiveness of ordinary forms if the sand rolls through

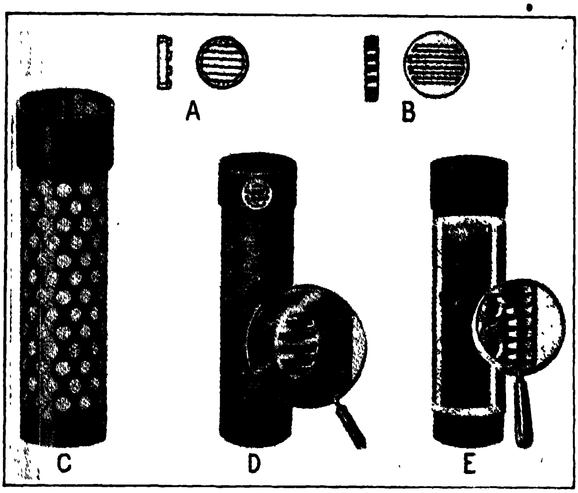


FIG. 184.—Types of screen pipe.
A and *C*, McEvoy wireless well strainer; *B* and *D*, Layne and Bowler, "Skrutite" button screen; *E*, Layne and Bowler wire-wound screen

the openings by gravity. It seems probable, however, that in most cases the sand grains are actually suspended in the oil, perhaps under the influence of gas and hydrostatic pressure. If such is the case, the sand grains would flow with the oil, quite independently of its natural angle of repose, and the form of the opening becomes of little or no importance. The size of screen opening must be proportioned to the average size of the sand grains which are to be excluded. If no water is present, the oil well pump is able to handle a considerable amount of sand without abnormal wear or loss of efficiency, and usually no effort is made to exclude the very fine sands which enter through any kind of screen that will admit a viscous oil. The screen openings should not be so fine as entirely to exclude the finer sands, otherwise they will clog about the screen openings and retard the flow of oil into the well. On the contrary they should be of such size that application of a swab will draw much of the accumulated loose material into the casing, so that it can be bailed out and the perforations and screens thus cleared. No rules can be laid down for the selection of a type and size of screen that will meet all conditions. Usually in each field or locality, the different available

screens must be tried under competitive conditions, and the one selected which gives the best results.

It is important that the screens be made of a material resistant to corrosion by acid or alkaline waters, with which they are often in contact. Brass and galvanized iron are the metals commonly used. In addition to resistance against corrosion, the material selected should resist the cutting or scouring action of fine sand, which is sometimes carried through the perforations under high gas and oil pressures. In high-pressure flowing wells, it is advisable to protect the well equipment by maintaining some back pressure by restricting the outlet, thus holding back the sand and minimizing its scouring action.

The operator must decide for himself whether or not screens are necessary or desirable. In many cases perforated pipe without screens will exclude sand sufficiently well, and will offer less resistance to the passage of oil. In some fields it is necessary to allow sand to enter with the oil to maintain the maximum production. In most cases, however, screens will be desirable in order to prevent sand from entering, with consequent increased expense due to the necessity of lifting it to the surface, and to wear on the pump parts, and to the necessity of separating it from the oil after reaching the surface. Furthermore, removal of large quantities of sand from about the well causes caving of overlying strata, which may collapse or bend the pipe, or which may permit water to enter the oil sand from an overlying water zone.

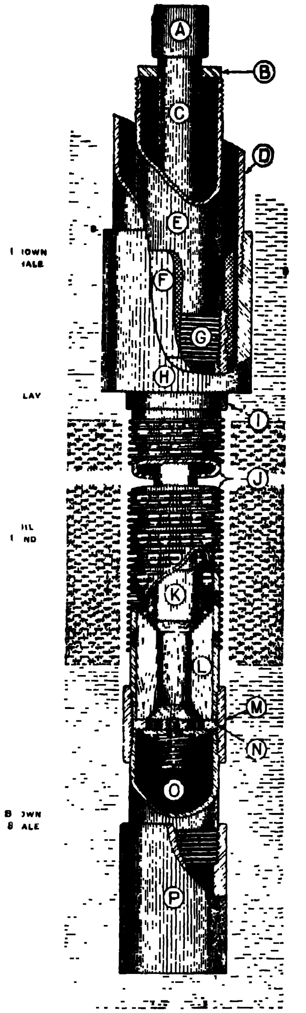
Methods of Setting Screen Pipe.—Bearing in mind the purpose of screen pipe and the weakening effect suffered by the metal as a result of the boring, cutting or punching of numerous holes, it is apparent that the liner must be so handled in the well as to avoid placing undue strain upon it, or great external friction which might displace the wire screening. Also, the screen openings must be left free from mud, sand or other material which might prevent the passage of oil through them.[4] It is advisable to completely wash all mud from the lower portion of the well before attempting to set screened pipe.

If the wall rocks are firm and free from mud, it may be possible to withdraw the oil string, place the proper amount of screen pipe on the lower end and lower it again without danger of the walls caving about the screen pipe as it is introduced. In loosely cemented sands, however, a method must be adopted which will prevent contact of the screen pipe with the walls of the well until it is in place. This is accomplished by inserting the screen pipe as a liner which must be small enough in outside diameter to pass within the oil string which penetrates the oil sand. The screen pipe liner is plugged at the lower end, and is lowered on a column of 2 or 3-in. tubing connected with the screen pipe by a casing adapter and a left-handed swaged nipple. The screen pipe liner is lowered until it rests on bottom, and the oil string is then raised until its

shoe is 10 or 12 ft. below the casing adapter on the liner. The tubing is then turned clockwise, unscrewing the joint at the left-handed swaged nipple, leaving the liner in the well with the adapter on top to serve as a guide for tubing or tools, which must subsequently be lowered into it. The walls usually close about the liner sufficiently, after the oil string is raised, to prevent the screen pipe from turning as the tubing is detached.

Occasionally the oil string will become frozen, so that it is impossible to raise it in this way. It is then necessary to perforate it in the well so that oil may pass, a liner of screen pipe being subsequently set inside if passage of sand through the perforations becomes serious.

Some operators float the screen pipe into position, simply plugging the lower end of the liner, filling the oil string with water and allowing the screen pipe to sink to bottom under the influence of gravity. The water usually checks the descent of the screen pipe so that it does not settle rapidly enough to cause damage to the pipe or screens. After the liner reaches bottom, the oil string is raised until the perforated pipe is exposed to the oil sand.



(*After E. W. Wagy in U. S. B. Mines Tech. Paper* 247).

FIG. 185.—Wash pipe for setting screen in rotary drilled well, permitting recovery of upper part of oil string.

A, wash-pipe coupling; *B*, steel ring; *C*, wash pipe; *D*, outside casing; *E*, back-off nipple with right and left thread; *F*,′ lead seal; *G*, left-hand thread; *H*, casing shoe; *I*, lead seal coupling with right and left thread; *J*, screen pipe; *K*, wash-pipe coupling; *L*, wooden wash plug; *M*, coupling; *N*, back-pressure valve; *O*, short nipple; and *P*, casing shoe.

"Drilling in" with Shop-perforated Pipe.—If the position and thickness of the oil-producing stratum are definitely known, as is usually the case in a partially developed field, the proper length of shop-perforated pipe may be placed on the bottom of the oil string just before the oil sand is penetrated.[4] This obviates the necessity of removing the oil string after the hole is completed, an advantage in unconsolidated oil sands, which often tend to cave or heave when the casing is withdrawn, or which may freeze about the pipe so that withdrawal is impossible.

Use of Wash Pipe in Setting Screen Pipe.—If mud-laden fluid has been used in the well, as in rotary drilling, or if for any reason mud has settled to the bottom, it will be necessary to wash the mud from the oil sand in order that it may not interfere with production; but in doing so, there is danger of the sand caving into the open hole before the screen pipe can be inserted. In order to avoid this difficulty and still clear the sand pores of mud, it is customary to resort to the use of a wash pipe.[4] This is a tube of smaller diameter than the oil string—usually

2 or 3 in.—which extends through the perforated portion of the string and is packed off at its upper and lower ends, above and below the perforations (see Fig. 185). The wash pipe serves merely to conduct water through the perforated pipe so that it reaches the bottom of the oil string without escaping through the perforations. If rotary equipment is in use, the oil string is often equipped with a rotary shoe or fishtail bit to aid the pipe in cutting its way through the clay which has settled and accumulated in the bottom. The packing device at the lower end of the wash pipe is sometimes provided with a back-pressure valve which prevents heaving sand from forcing its way up inside of the casing.

The oil string, with the screen pipe and wash pipe in proper position in the column, is lowered until the shoe is a few feet off bottom, pumping water through the upper casing and wash pipe to aid in clearing away the mud while the casing is being lowered. When the shoe is but a few feet off bottom, prolonged circulation down through the wash pipe and back to the surface, through the annular space about the pipe, will gradually remove the mud until the sand faces are clear. When the circulating fluid ceases to bring mud to the surface, a string of tubing is lowered into the casing, screwed into the collar on the upper end of the wash pipe, and the latter is slowly withdrawn. As the wash pipe is raised through the perforated pipe, water is continuously circulated through it in order to clear the perforations of accumulated clay and sand. This hydraulic pressure also aids in removing the wash pipe if sand has settled tightly about it. If there is no necessity for clearing the perforations and hydraulic pressure is not necessary to aid in lifting the wash pipe, it may be removed with the aid of a tubing spear run on a wire cable instead of using tubing as suggested above.

Special patented forms of wash rings, for use as packers about wash pipe, make use of babbitt or lead seals or glands packed with hydraulic packing. These are more effective and reliable in action than the simple disc packers illustrated in Fig. 185, but serve a similar purpose.

Plugging the Bottom.—To prevent sand and water from entering the space within the oil string, it is customary to plug the lower end of it with a wooden, lead or cast-iron "heaving plug." The various forms of plugs have already been adequately described in connection with cementing operations in Chap. IX.

Swabbing to Clear Perforations, Screens and Sand Pores.—The method adopted for placing the oil string or liner often leaves the perforations or screens clogged with clay or sand. It often happens also, unless the mud can be washed from the well by circulating clear water, that the walls will be plastered with clay and the rock pores clogged so that oil does not flow freely. In such cases the application of a swab will usually remedy the condition by drawing the mud into the casing so that it can be bailed out.

The swab (see Fig. 186) is a rubber-faced hollow cylinder with a pin joint at the upper end to connect with the drilling tools, and on the lower end is placed a check valve opening upward. The steel body of the tool is constructed of perforated tubing, the fluid having access to the inside of the rubber cylinder through the perforations. The rubber sleeve can be expanded to fit snugly within the casing by compressing it longitudinally. This is accomplished by tightening the pipe coupling on the lower end, against the metal ring which supports the rubber cylinder.

The swab is lowered slowly to the bottom of the well on the drilling cable, the well fluid lifting the check valve, passing up through the inner tube and into the space above, through holes drilled in the wrench squares. On reaching bottom, power is applied and the swab is rapidly pulled out of the well. The check valve prevents the well fluid from again passing through the swab, and it is pushed ahead of the latter to the surface. The rubber cylinder is only slightly smaller than the inner diameter of the casing, and when the fluid pressure is brought to bear against the

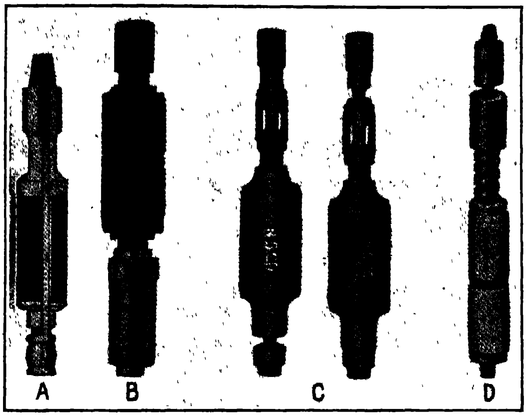


FIG. 186.—Types of swabs.

A, "Ideal" swab; *B*, Beam swab with unloader; *C*, Kline swab with plunger valve; *D*, Heeter's swab.

inner surface of the rubber (through the perforated supporting pipe), it is expanded until it presses firmly against the casing, effectively preventing leakage of fluid around the cylinder. Because of the small clearance between the rubber and the pipe, it is important that the inner surface of the casing be free from indentations and blisters; otherwise the rubber cylinder will be rapidly destroyed and there will be considerable resistance to movement.

In addition to providing a means of rapidly and effectively removing all fluid from the well, application of the swab creates a partial vacuum within the casing, which draws oil, loose sand and clay through the perforations. The perforations and screens are thus cleared of obstructions and a flow of oil into the well is established. After the swab has been removed, the bailer is lowered to remove sand and mud which has been drawn through the perforations.

It is important in operating the swab not to trap more fluid above it than the power is able to lift or than the swab is designed to support. An improved type of swab is equipped with a valve combining the principles of a vertical check valve and a pop safety valve, which automatically releases any excess fluid beyond that for which the valve is set.

"Shooting" for Production

The use of explosives in stimulating production is widely practiced in regions where the producing strata are hard, close-grained rocks which offer unusual resistance to the flow of oil into the well. Limestones are characteristic of this class, and are usually shot with a charge of nitroglycerin, blasting gelatin or dynamite as soon as the well is completed, to open channels through the reservoir rock and to stimulate the flow.

Nitroglycerin, which is the explosive generally employed for this purpose, is charged into long, tinned, sheet-iron cylindrical containers called "torpedoes" or "shells." From 5 to 300 qt. of explosive are used, depending on the nature and thickness of the stratum to be shattered. The shells are usually about 1 in. smaller in diameter than the casing through which they are to be lowered, and vary in length according to the capacity desired. Capacities are commonly 10, 20 or 30 qt., and as many shells will be used in the "shot" as may be necessary to make up the total quantity of nitroglycerin considered necessary. The shot is customarily submerged in from 100 to 200 ft. of water to serve as "tamping" for the charge. This causes the explosive to expend its energy laterally and downward instead of upward. The well casing should be drawn up above the level of the well fluid if possible. The casing is occasionally ruptured at the fluid surface unless this is done.

The upper end of each shell is equipped with a bail by means of which it is suspended from a hook on the end of a steel or tarred manila torpedo line, which serves to lower it from the surface to the desired point in the well. This line is carried over a small pulley, supported in a stationary position a few feet over the mouth of the well, and is wound on a special reel which is customarily attached to the flywheel of the engine, though it is also equipped with a crank and supports so that it may be mounted separately and operated by hand. The hook on the end of the torpedo line which supports the shell is so designed that on lowering it slightly after the shell rests on bottom, the hook is detached from the torpedo bail so that it can be withdrawn, leaving the shell in the well.

The shells are ordinarily filled while suspended in the well, so that the upper end is at a convenient level for pouring in the glycerin from the 10-qt. cans in which it is shipped from the manufacturers. After filling, the shell is washed off with water to remove any drops of glycerin that may have splashed out of the container.

Ordinarily the well will have been drilled entirely through the oil-bearing stratum or zone, and to a slight depth below into the underlying formations. Since the shot is generally confined to the space within the well immediately opposite the oil stratum, it will be necessary to support the first shell lowered, at the proper distance off bottom, so that the charge will not extend below the oil zone. In order to accomplish this,

the first shell placed in the well will have attached to its lower end an "anchor" of proper length, composed of tubing about 1¼ in. in diameter. When the first shell has been lowered until the anchor rests on bottom, other shells are loaded and lowered successively so that they rest end to end on the first shell. If the shells are much smaller in diameter than

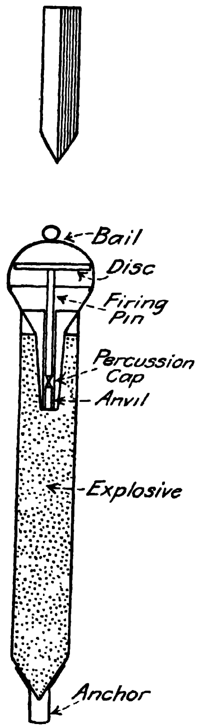


FIG. 187.—Impact detonating device for use with "go-devil."

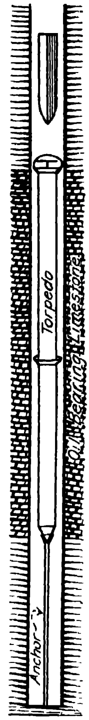
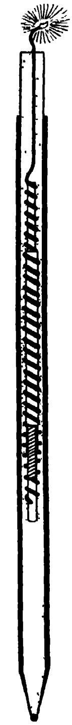


FIG. 188 Illustrating use of torpedo in "shooting" oil-bearing formations.



(*After W. H. Jeffery*). FIG. 189.—Jack squib.

(*After W. H. Jeffery*). FIG. 190.—Bumper squib.

the hole, each should be equipped with a disc at the upper end nearly as large in diameter as the casing, to prevent two shells from being placed side by side in the well instead of end to end (see Fig. 187).

The uppermost shell is often equipped with a detonating device consisting of a sheet metal disc of about the same diameter as the shell, supported in a horizontal position by a vertical firing pin, which bears upon a fulminate of mercury blasting cap[3] (see Fig. 188). A common method of firing the charge is to drop a "go-devil," a short bar of cast iron, from the surface, striking the disc and detonating the fulminate

cap. An alternative method of firing involves the use of a "squib," of which there are several types. Fig. 189 illustrates a "jack" squib, which consists of a double-walled tin shell, 2 in. in diameter and from 3 to 5 ft. in length, and containing half a pint of nitroglycerin or a stick of dynamite. Several feet of waterproof fuse, with a fulminate of mercury cap at the lower end, are wrapped about the tube containing the explosive. The end of the fuse projecting from the upper end of the squib is ignited and the device is dropped into the well on top of the charge. The length of fuse must be varied to correspond with the depth of the hole and the depth of well fluid on top of the charge, but varies from 2 to 10 ft. Other types of squibs not so commonly used as the jack squib, are the "line" squib and the "bumper" squib. The former consists of a short shell weighted so that it will sink freely through the well fluid, and equipped with a firing head and three percussion caps. The line squib is lowered on a wire until it rests on the charge, and a nipple or short length of pipe is dropped over the wire to fire the squib. The "bumper" squib consists of a small shell filled with nitroglycerin and equipped with a firing head and pin and a percussion cap. A 4-ft. length of 2-in. pipe is attached to the top of the squib in such a way that the firing head is exposed in the lower end of it (see Fig. 190). The wire on which the squib is lowered into position passes freely through the bail on the upper end of the pipe, and a heavy weight, such as a sash weight, is fastened on the end of the line below the bail. As the squib is lowered, the sash weight supports the bail, but when the squib comes to rest on the charge, release of tension in the line at the surface permits the sash weight to descend, striking the firing head and detonating the charge.

Many operators prefer to fire explosives electrically, and for this purpose the last shell lowered is equipped with an electric blasting cap, and is lowered on the sand line to which is bound an insulated copper wire. When all is in readiness, a blasting machine at the surface sends a current of electricity down through the copper wire and fires the charge. This method of firing is preferred in cases where the walls of the well tend to cave. The casing is customarily drawn up several hundred feet above the explosive after the shells are in position, and if the walls cave the charge may be covered with mud or debris so that a go-devil or squib cannot reach it. With electric firing, unless the wire is broken, the charge may be fired even though the walls do cave.

Occasionally when the well does not extend below the oil-producing stratum, the metal containers for the explosive are dispensed with. The nitroglycerin is in this case lowered in a specially designed container resembling a dump bailer (see page 270), which permits the explosive to flow out into the well when it reaches bottom. Successive trips are made until the hole is filled with the glycerin up to the top of the oil zone, and the charge is then fired with a squib.

Because of the sensitive character of nitroglycerin, every precaution must be taken in handling it to prevent accidental explosion. It should not be transported in leaky cans. Undue friction and jarring of the containers should be avoided. The empty cans should be disposed of. Loading and firing of nitroglycerin are customarily done by skilled "well shooters" who undertake full responsibility for the work on a contract basis. The average cost of such work in the fields of Ohio, Illinois and Indiana is about $3 per quart.

Special care must be taken in placing the shot so that it does not damage the casing and other well equipment. Accurate depth measurements are necessary in order to place the charge at just the proper point in the well, otherwise the cap rock overlying the oil zone may be fractured, permitting oil and gas to escape or water to enter the oil bearing rocks. The line on which the explosive is lowered should be "flagged" or marked a hundred feet or so above its lower end, and on drawing the line out of the well after lowering a shell, the lower end below the flag should be hoisted out slowly. Occasionally the torpedo line hook does not disengage itself from the torpedo bail, and if the shell is hoisted back to the surface and permitted to strike the line pulley over the well, a disastrous explosion might result.

Nitroglycerin free from excess acid will not explode at temperatures normally encountered in oil wells, but slow decomposition results at temperatures above 140°F., and in some deep wells the explosive apparently undergoes decomposition and explodes spontaneously after a period of from 2 to 100 hr. In the deep territory of the Ranger field, shots are customarily allowed to explode in this way without the aid of detonating devices.

A powerful shot of nitroglycerin exploded in a well probably results in the formation of a large cavity, with fractures extending out in all directions. Expansion of the gases of explosion causes a rush of fluid, mud or dust and rock fragments from the well, which is often accompanied or followed by a flow of oil and gas. Due to the restricted diameter of the well, there is a surprising delay in the effect of the explosion at the surface after the charge is fired. In a deep well, vibration of the casing gives warning of the explosion many seconds before the rush of gas reaches the surface and before the sound is heard. In expectation of a shower of water, oil, gas and debris from the well, the rig should be in the sole possession of the shooter when the charge is fired, and he must seek a place of safety as promptly as possible thereafter.

Additional data on well shooting will be found in Chap. VIII.

A SELECTED BIBLIOGRAPHY ON THE SUBJECT MATTER OF CHAPTER XI

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3. Jeffery, W. H.: "Deep Well Drilling," Published by W. H. Jeffery Co., Toledo, Ohio, 1921. See particularly, Chap. IX, XI and XII.
4. Wagy, E. W.: Perforated casing and screen pipe in oil wells, U. S. Bureau of Mines, *Technical Paper* 247, 1920.

See also References 1, 2, 3, 4, 5, 14 and 15 at end of Chap. V.

CHAPTER XII

PRODUCTION METHODS; REMOVAL OF OIL FROM WELLS

In the preceding chapters, methods and equipment used in drilling the well and preparing it for production have been described. The present chapter and the next will deal with the problems of production or extraction of the oil and gas.

Assuming that the well has been properly finished in a productive oil sand, oil enters and accumulates within it by reason of the difference in pressure between the reservoir rock and the space within the well. Oil will continue to enter, and the fluid level will rise in the well, until the fluid pressure is equivalent to the reservoir pressure; then no more oil enters unless some is removed from the well. The level to which the oil rises has an important bearing upon the method of extraction employed. In some cases it rises until it overflows at the surface, in which case no mechanical pumping device is necessary. As described in the preceding chapter, the pressure behind the oil is sometimes so great that it is thrown high into the air above the casing head. The presence of gas in or associated with the oil is usually an important factor in causing natural flow. If gas is present in quantity, it is dissolved in or occluded in the oil, so that the oil density is materially reduced and a higher fluid level in the well is necessary to offset the pressure within the reservoir rock. Larger volumes of high-pressure gas flowing from the producing sand may lift the entire superimposed column of oil to the surface in its effort to expand and escape from the well. The action of gas in the latter case is comparable with that of steam in producing intermittent flow of water from geysers.

Pioneer wells in virgin territory often "come in" as gushers, and during the early period of development fluid levels are customarily high, so that flowing wells are common. As development proceeds, however, and the field pressure declines, initial productions of new wells become smaller and fluid levels subside. Eventually gas pressure becomes almost negligible in its effect upon fluid levels, and continued pumping will depress the level of oil within the wells below the top of the productive stratum, so that gravity becomes a factor in drainage of oil from the reservoir rock.

Flowing Wells.—Problems encountered in the control of high-pressure flowing wells have been adequately discussed in Chap. X, and the massive valves provided for such wells were described in some detail. High-pres-

sure wells may continue to flow for months, the lead lines carrying the oil directly into storage with practically no expense involved, other than occasional repair or replacement of valves and well fittings.

In the case of flowing wells producing from loosely consolidated sands, it is often necessary to restrict the flow somewhat in order to prevent "heaving" of loose sand into the well with the oil. This may be done by partially closing a valve on the lead line; it may be accomplished by passing the oil and gas through a trap which places "back pressure" on

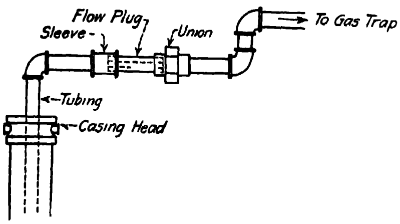


FIG. 191.—Arrangement of flow nipple for holding back pressure on a flowing well.

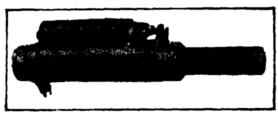


FIG. 192.—Adjustable flow nipple.

the well (see Chap. XVI); or a restriction or "flow nipple" may be placed in the lead line (see Fig. 191). In the initial stages of production of high-pressure wells in certain fields, it is customary to use flow nipples as small as ½ in. in diameter, pressure within the well being thereby maintained several hundred pounds above atmospheric pressure. As the pressure declines and sand displays less tendency to flow into the well, the flow nipples are gradually increased in diameter until the full size of the lead line with no back pressure is attained. A patented type of flow nipple, in which the size of the opening through which the oil must flow is variable and adjustable, is illustrated in Fig. 192.

Wells frequently flow "by heads," that is, they produce intermittently, short periods of flow alternating with brief periods of quiescence. This action is due to the gradual accumulation of gas in the bottom of the well. When sufficient gas has formed, the entire column of oil above is forced out of the well, followed by a period of "blowing," marking the escape of the liberated gas. More oil enters the well, establishing equilibrium with the pressure in the sand. Then follows a period during which gas again accumulates until the flow is repeated.

Eventually in the history of every flowing well, there comes a time when the gas pressure and volume is insufficient to cause natural flow. The fluid level within the well may still be high, however—perhaps within a short distance of the surface. There follows an intervening period before mechanical pumping of the well is necessary, in which the forces are about evenly balanced, flow occurring intermittently. At this stage it is usually possible to induce flow, and thus continue for a time the

production of oil without the necessity of pumping. This may be accomplished by agitation of the oil or by restricting the diameter of the tubing through which the oil is produced.

Gas has less opportunity to rise through oil in a pipe of small cross-section than it has in pipes of large size. Hence, in a small pipe, the gas present in the oil is more effective in causing movement. Assuming that the amount of gas produced by the well remains constant, it is clear that when mixed with the oil it would occupy a larger proportion of the space within a small pipe than in a large one, and the weight of the column of fluid is correspondingly less. For the same reason oil often flows through the annular space between two strings of pipe when it will not flow through either pipe alone.

Agitation of oil in the well has the effect of liberating occluded and dissolved gas which accumulates in large enough quantities to induce flow. Agitation may be accomplished by hoisting and lowering the bailer through accumulated oil in the well, or an "agitating string" consisting of a column of 2- or 3-in. tubing may be raised and lowered through the accumulated oil in the well. In some localities it is customary to agitate the oil periodically—usually daily—agitation causing flow of all or most of the oil that accumulates in the well. In the Sunset field of California, wells have been operated for years after natural flow has ceased, by this method, at a cost materially lower than would be incurred in operating pumps. In this field, the large quantity of fine sand produced with the oil, and its destructive effect upon any mechanical pumping device, is also an important factor in necessitating the use of methods for inducing intermittent flow.

In some fields, explosives are used to induce flow, wells being periodically "shot" with nitroglycerin or dynamite, after which a flow of oil lasting for several days or weeks, will occur. The use of explosives for this purpose and their manner of application have been adequately discussed in Chap. XI.

Extraction of Oil from Wells by Mechanical Means

When wells may no longer be induced to flow, it becomes necessary to apply mechanical methods for accomplishing removal of the oil. These include bailing methods, swabbing methods and pumping methods. The latter include pumping with the oil well plunger pump in its various forms, and pumping with the air lift.

Extraction of Oil by Bailing.—In some regions, notably in the oil fields of Russia, Galicia and Roumania, it is customary to remove oil from the wells with the aid of dart valve bailers, somewhat similar to those used in connection with cable drilling. The method is seldom used, except temporarily, in American practice. Where the bailing process is used by

preference, the wells are usually of large diameter and produce considerable quantities of sand along with the oil.

The bailers employed for production purposes vary in diameter from 6 to 14 in., and range from 10 to 60 ft. in length, depending upon the diameter of the well. The greater lengths are used only to give added capacity. They are usually made of riveted sheet steel with soldered joints, and a steel bar about 5/8 in. in diameter extends between cross-bars placed near the top and bottom, to prevent the bailer from pulling apart when subjected to unusual strain. The upper and lower ends are sometimes slightly tapered to protect the bail and the foot piece containing the valve from damage by catching on obstructions in the well. For use in crooked holes, a flexible-jointed type of bailer has been devised.[8]

When the bailer is used for extracting oil, it is in motion practically continuously, so that the type of sand reel ordinarily used on the cable drilling rig is inadequate on account of its small size and the tendency of the bearings to overheat. Consequently, a special bailing drum, varying in diameter from 3 to 5 ft., has been developed. This is operated by a belt drive direct from the engine pulley, a tight-and-loose pulley on the hoisting drum shaft making it possible to readily apply or disconnect the power by shifting the belt. With such equipment, it is possible to hoist the bailer filled with oil at a speed of from 1,000 to 1,500 ft. per minute with an expenditure of from 30 to 50 hp., depending upon the size of bailer used and the quantity of water and sand to be handled. A crucible steel wire bailing cable, 5/8 in. or 3/4 in. in diameter, is commonly employed. Due to constant abrasion on the walls of the well and casing, the cable has a short life.

Considerable skill is necessary on the part of the operator in manipulating the bailer, when the well produces gas or sand along with the oil. Agitation of the oil with the bailer will often liberate gas which causes the well to flow while the bailer is in the well. At such times the bailer and its cable may be violently ejected. Unless precautions are taken to keep the bailer in motion, there is also danger of its being buried in the well by a sudden flow of sand. Care must be taken to slacken the speed of hoisting or descent, when the bailer is leaving or entering the fluid in the well; otherwise severe torsional strain is thrown upon the cable by the sudden change in tension. If the oil contains much gas, bailing may become difficult, because expansion of the gas ejects most of the oil from the bailer before it reaches the surface. Because of this, the bailer often reaches the surface containing only about one-tenth of its capacity of oil.

Automatic Bailer for Oil Recovery.*—An electrically operated automatic bailer for the raising of oil from wells has been developed and successfully applied on a California

* Huguenin, E., Automatic bailer for oil recovery, Summary of Operations, California Oil Fields, vol. 7, no. 9, Mar., 1922. *Seventh Annual Report of the California State Oil and Gas Supervisor.*

property, in a well that produces too much sand for economic operation with the plunger pump. A scow-bottom sand pump, 50 ft. long, holding about 1 bbl. of oil, is used as the bailer, which is hoisted from and lowered into the well by an electric motor, equipped in much the same way as an automatic elevator. Upon emerging from the well, the bailer passes into an iron cage attached to the casing head, which lifts the bailer valve and discharges its oil into a tank. The bailer travels at a rate of 300 ft. per minute, and a round trip of the bailer is made in 7½ min. when bailing from a depth of about 1,000 ft. Automatic delay switches allow a period of rest of ¼ min. at the bottom of the well, and ½ min. at the top for the oil to drain from the bailer. By this device the expense of frequent pulling and replacing of tubing and rods is avoided, and the bailer is said to have a swabbing effect which aids in keeping the perforations open. As a result, the daily production of the well has increased from 12 to 60 bbl. The apparatus is considered impractical for deep wells of large production.

Extraction of Oil from Wells by Swabbing.—In wells producing too small a quantity of oil to justify continuous operation of a pumping device, swabbing is sometimes resorted to as a means of extracting the oil. The swab has already been adequately described (see page 330). Lowered through the oil to the bottom of the well, it is rapidly hoisted out, lifting the entire column of accumulated oil to the surface. Suction, produced by rapid removal of the swab, creates a partial vacuum below, which operates to draw more oil into the well so that the process may soon be repeated. The swab is effective in handling oil containing sand, though there is some danger of the swab becoming so packed with sand that its removal from the well is difficult. Considerable power is necessary in hoisting the swab from the well, and care must be taken to avoid lowering it into a column of fluid to such a depth that the available power for lifting is inadequate. Wear on the friction surfaces of the swab is excessive, particularly when the oil carries sand, and leakage between the swab and the casing may greatly reduce the efficiency of the method, unless the packing rings are frequently replaced. The swab may only be used when the well is lined with a single, straight column of screw casing, free from projections on its inner surface.

Extraction of Oil from Wells with the Plunger Pump

When wells cease to flow and mechanical means must be provided for lifting the oil, the oil well plunger pump is generally employed. This is a displacement pump, simple in design and positive in action. It is submerged in the oil on tubing, through which the fluid is pumped to the surface. The column of tubing either rests on the bottom of the well, or it must be suspended from the casing head.

While there are many different variations in design, the plunger pump has certain essential and characteristic parts common to all types. There must be two valves, each consisting of a simple steel ball resting upon a beveled steel, disc-shaped valve seat (see Fig. 193). The ball is enclosed within a cage screwed to the seat, thus preventing displacement of the

two parts. One of these valves (the "standing valve") is mounted in a stationary position in the bottom of a "working barrel" of cast iron or steel, with polished interior surface. The second valve (or "working

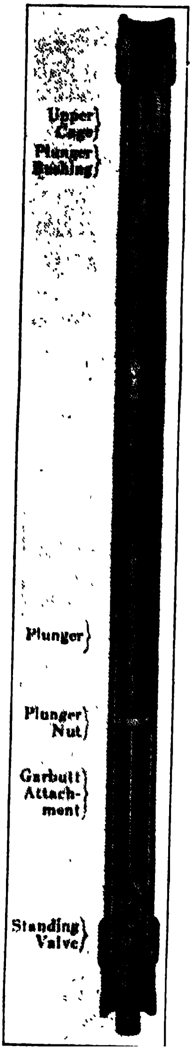


FIG. 194.—Oil well plunger pump.

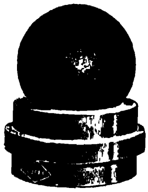


FIG. 193.—Ball valve and seat for plunger pump.

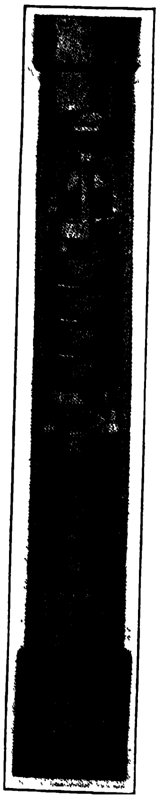


FIG. 195.—Simple form of oil well pump using short leather-packed plunger.

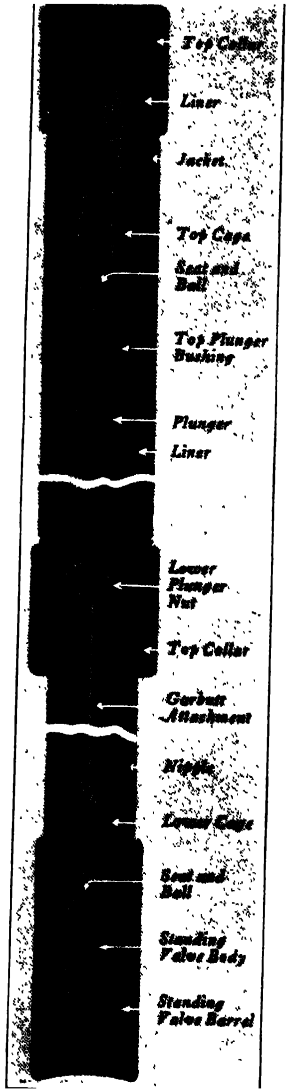


FIG. 196.—Axelson plunger pump with replaceable liner and extension nipple.

valve") is mounted on a plunger which operates as a piston within the upper part of the working barrel. The working barrel is attached by a screw connection to the lower end of the well tubing, while the plunger

is suspended on a column of cylindrical steel "sucker rods," varying from $\frac{9}{16}$ in. to 1 in. in diameter, depending upon the depth of the well and the size of the pump, and extending down from the surface through the tubing. The churning or reciprocating movement of these rods gives the plunger and working valve the necessary motion. The relation of the several parts of the plunger pump is illustrated in Fig. 194.

The form of the plunger varies considerably in different models. A common type consists of a seamless steel cylinder, polished on its outer surface, and accurately dimensioned to fit snugly within the working barrel. The upper end of this cylinder supports the working valve and its cage, which serves to connect it with the sucker rods, extending to the source of power at the surface. The standing valve rests in a cone-shaped recess in a foot piece attached to the lower end of the working barrel, and may be pulled up out of its recess by means of the "garbutt rod." The latter connects with the cage on the standing valve, and extends up through a cross-bar or loose guide nut in the lower end of the plunger. At its upper end, the garbutt rod terminates in a nut which will not pass through the opening in the plunger nut or cross-bar, though the rod itself freely does so. The position of the plunger is so adjusted in the working barrel that in ordinary operation the plunger nut slides up and down on the garbutt rod without striking the garbutt rod nut. Hence, the standing valve remains stationary with respect to the working barrel. If it is desired to remove the valves for repairs, however, drawing up on the sucker rods will cause the garbutt rod nut to engage the plunger nut, thus withdrawing both valves without the necessity of disturbing the tubing and working barrel. The aperture through the plunger nut about the garbutt rod is amply large to pass the full amount of fluid admitted to the working barrel at each stroke of the plunger.

Cycle of Operations of the Oil Well Plunger Pump.—It will be observed from the above generalized description of the oil well plunger pump, that pumping of the oil is accomplished by the churning motion of a plunger equipped with a moving valve, in a cylinder or working barrel provided at its lower end with a stationary valve. Assuming that the plunger has just completed its down stroke, the two valves will be momentarily at rest with respect to each other, and both will be closed. As the up stroke is in progress, a partial vacuum is created within the working barrel between the two valves, the standing valve is thereby raised from its seat, and oil is drawn into the barrel. As the plunger completes its up stroke and the suction effect due to its movement ceases, the standing valve drops back upon its seat and prevents the oil that has entered the barrel from flowing back into the well. On the down stroke, the oil within the barrel, unable to escape through the lower or standing valve, is put under compression and lifts the upper or working valve from its seat. As the plunger descends, the oil within the barrel is forced

through the upper valve to the extent of its travel. On completion of the down stroke, the upper valve drops upon its seat, and as the plunger rises on the following stroke, the oil thus displaced by the working valve is lifted into the tubing above the working barrel. On the next and succeeding strokes, more oil will be forced up into the tubing until it overflows at the surface into the storage tanks or sumps provided. Once the tubing is filled with oil, as much oil is lifted to the surface with each stroke as enters the pump.

Types of Oil Well Plunger Pumps.—A variety of different forms of pumps containing the essential features described are met with in practice. Some are especially designed to facilitate repairs and replacement of worn parts. Others are said to be adapted to the handling of oil containing sand and gas which often cause difficulty in the operation of the ordinary type of pump.

Sometimes the garbutt rod is omitted and the upper and lower valves are entirely separate. For shallow well service, instead of using a cylindrical steel plunger, a piston will be made of a valve mounted on a short metal guide, equipped with cup leathers or canvas, fiber or leather washers (see Fig. 195). In this case the lower end of the piston is often equipped with a nut fitting a screw connection on the top of the cage of the standing valve. In ordinary operation, the piston carrying the working valve does not descend in the working barrel to the level of the standing valve, but when it is desired to remove the lower valve for repairs without withdrawing the tubing and barrel, the upper valve is lowered and turned until the threads engage, when the two valves are withdrawn together. The standing valve is also equipped with some form of packing, usually leather washers or a woven hemp packing, which is wedged into the conical opening of the foot piece at the lower end of the working barrel. The lower valve may be forced into its recess while suspended from the upper valve, and unscrewed from the latter without the necessity of removing the tubing and working barrel.

Instead of being made as a solid casting, working barrels are sometimes equipped with a replaceable seamless steel liner. This feature facilitates repair work and is especially adapted to use in wells where sand rapidly destroys the polished surfaces of the barrel and plunger. Another type of working barrel is made up of short sections, any of which may be readily replaced without the necessity of scrapping an entire barrel (see Fig. 196).

In some cases the standing valve is placed in a short separate barrel, separated from the plunger barrel by a nipple of ordinary pipe (see Fig. 196). This arrangement permits of operating the pump in such a way that the plunger does not extend out of the working barrel at either end of its stroke, thus preventing the polished outer surface of the plunger from being exposed to sand or grit, and giving it a longer life. If the oil carries much sand, however, this arrangement of parts may allow the sand to settle in the space about the connecting nipple, making it impossible to pull the standing valve when repairs are necessary.

In some pumps the working valve is placed in the lower end of the plunger. If much gas enters the pump with the oil, it will soon form a body of gas which will be alternately compressed and expanded between the two valves, thus preventing their proper action and greatly reducing the efficiency of the pump. Placing the valves closer together, as is done when the working valve is placed in the lower end of the plunger, reduces this difficulty due to compression of gas to a minimum.

The lower end of the foot piece containing the standing valve is threaded to receive tubing of the same diameter as that on which the pump is suspended. One

or more joints of tubing—frequently enough to reach to the bottom of the well—perforated with ¼- to ½-in. holes, is customarily attached to the foot piece. A cap is screwed on the lower end of this tubing so that all oil reaching the standing valve must pass through the perforations. This device, sometimes called a "gas anchor," by admitting oil from a point sufficiently below the fluid surface largely prevents admission of gas to the interior of the pump. Instead, the gas rises through the oil to the fluid surface, and to the well mouth through the annular space between the casing and tubing, escaping through the side outlets of the casing head.

Valves and seats are preferably made of hardened tool steel to resist wear. The balls are as nearly spherical in form as it is possible to make them, and they range from 1 to 2¼ in. in diameter. The seats are disc-shaped, and are made reversible in order to give maximum service. That is, the inner circular edge on either side of the disc is beveled where it makes contact with the steel ball. The ball and seat should be ground together to secure proper seating. Hard brass balls and seats are used when the pump must handle corrosive ground waters, often associated with the oil.

Instead of a ball, the Parker working valve is equipped with a disc-shaped valve mounted on a cylindrical steel stem (see Fig. 197). The sucker rods are attached to the screw connection at the upper end of the valve stem, which projects through the top of the cage casting. The valve seat is threaded on its outer edges to connect the valve cage with the pump working barrel. The valve is held in position on the lower end of the stem by a nut. With each down stroke of the pump, movement of the stem through the cage and seat causes the valve to be depressed with respect to the seat, until the shoulder on the upper end of the stem strikes the top of the cage. On the up stroke, the valve ascends and presses up against the seat with the full weight of the pump plunger suspended from the valve seat. This valve is positive in action and is especially recommended for pumping heavy viscous oil and for oil carrying sand.*

Sucker Rods.—The connection provided between the pump plunger and the source of power at the surface, may be either metal or wooden rods, metal tubing or wire rope. For shallow well service in some regions, round or octagonal wooden poles, often of ash, are used. These are connected, end to end, with metal straps riveted to the poles and coupled together with tapered screw joints. The chief advantage of the wooden rods is their lightness and greatly reduced weight when submerged in liquid. They are much weaker than steel rods, however, and cannot be so easily connected.

Sucker rods of steel are generally preferred to other types, and in deep-well pumping this form of power connection is universally used. These rods are manufactured in 20-, 25- and 30-ft. lengths, round in cross-section, and vary from 9/16 to 1 in. in diameter. They are usually provided with "box and pin" tapered screw joints, ranging from 7/8 to 1¼ in. in diameter, the forged and machined screw connections being welded on the ends of the round rods. The Axelson* upset-end sucker rod is equipped with a tapered pin joint at each end, the rods being connected in this case by separate forged steel couplings with a tapered box joint in each end. By using a double joint of this type, the coupling is of larger diameter than the pin ends of the rods, so that any wear which occurs is imposed upon the coupling. This permits of replacement of worn parts at minimum cost (see Fig 198)

Flexible steel wire cable is occasionally used instead of rods for operating plunger pumps in oil well service. Through the use of the Parkersburg wire line pumping equipment, the cable may be kept taut and the pump operated as satisfactorily as with the less flexible metal rods (see Fig. 199). The great advantage of wire cable as a power connection is found in the ease and rapidity with which the plunger and

* Manufactured by Axelson Machine Works, Los Angeles, Cal.

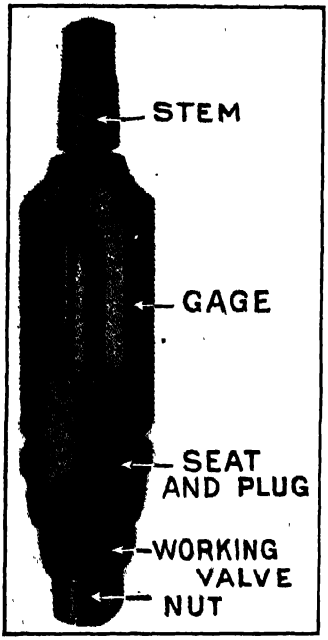


FIG. 197.—Parker working valve.

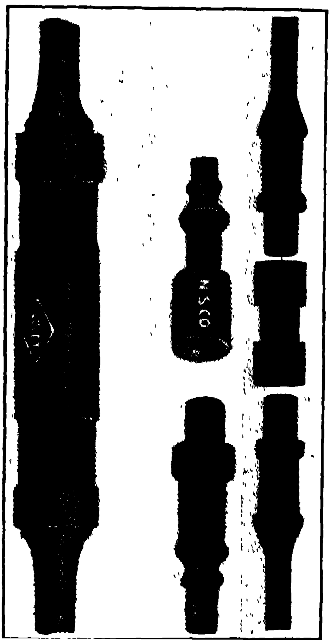


FIG. 198.—Types of sucker rod joints.

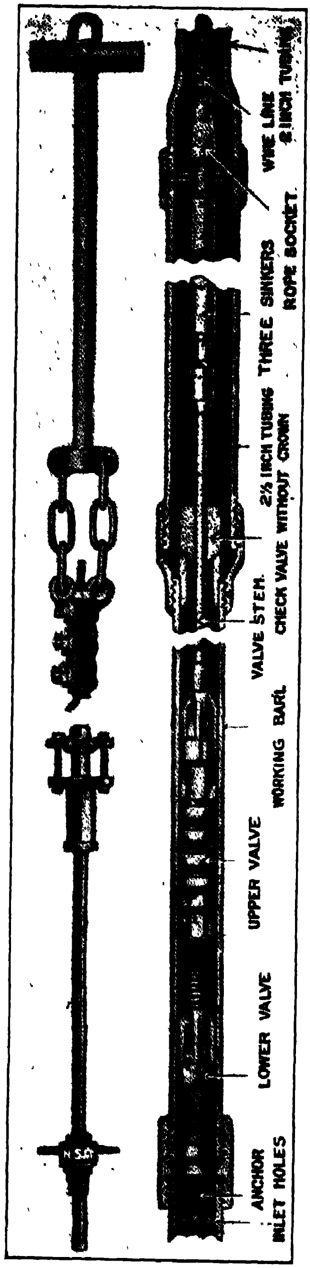


FIG. 199.—Wire line pumping equipment.

valves can be withdrawn from the well when repairs are necessary. Metal rods must be unscrewed as they are withdrawn, a rather tedious process; but the cable may be rapidly reeled on the bull wheel shaft or sand drum as the pump is raised. It is claimed that wire cable is less liable to breakage as a result of vibration, bending and crystallization than a solid rod; though wear, resulting from friction on the tubing, is more severe in the case of cable than with rods. A coarse-laid cable, composed of 6 strands of 7 wires each, resists abrasion more effectively than the 6 by 19 wire cables, and is therefore preferred for pumping service. Old drilling cable is often used for the purpose. A temper screw providing easy adjustment of the cable tension is used on the wire line outfit instead of the adjuster grip.

The tubing on which the pump is suspended is specially made for the purpose, being somewhat heavier than standard pipe, with collars longer than ordinary. The 2-, 2½-, 3- and 4-in. sizes are commonly used, and joints average 20 ft. in length. The joints nearly butt within the collars, and the inside edges are slightly chamfered to remove burrs which would damage the polished surface of the plunger during the process of lowering it through the tubing into the working barrel. The tubing should also be round and free from dents or seams, and should be tested before it is placed in the well by passing through it a wooden plug, only slightly smaller in diameter.

A type of tubing having upset ends is now widely employed in deep-well service. The extra metal is placed on the outside of the joint, and the metal left at the root of the threads is the full thickness of the regular tubing (see Fig. 100 and Table XXVI). The added strength given to the joint is of considerable value in avoiding parting of the column of tubing, which may occasion a tedious fishing job.

The tubing is often suspended in the well from the surface with the aid of a "tubing catcher" (see Fig. 200). This device is attached to the top joint of tubing, and contains slips which bear against the casing. It serves to support the working barrel at any distance off bottom without the aid of an anchor, and prevents the tubing from falling in case surface connections at the casing head fail.

Surface Arrangement of Pumping Equipment.—Above the casing head, the upper end of the tubing terminates in a stuffing box through which operates a polished rod of brass or steel, connecting at its lower end with the column of sucker rods (see Fig. 202). A tee placed below the stuffing box permits oil to escape from the tubing to the oil lead line which carries the oil to storage. The space about the tubing within the casing head should be packed off to prevent escape of gas, which flows to the surface through the space between the casing and the tubing. The gas lead lines from the side outlets of the casing head connect with the gas gathering system. The packing rings within the stuffing box fit snugly about the polished rod, permitting free movement of the rod, but preventing escape of the oil about the rod, even though the point of discharge of the oil lead line is at a considerable elevation above the casing head.

Power Connections.—The sucker rods are given the necessary oscillating movement in either of two ways: (1) by connecting with the end of the walking beam, or (2) by connecting with one corner of a triangular pumping "jack." The walking beam is customarily employed when the well is equipped with its own individual engine or motor, while the

pumping jack is used in connection with the multiple system of pumping, in which a group of wells is operated by a system of pull lines from a central "power."

When the walking beam is used as a means of applying power, the polished rod connecting with the sucker rods below the casing head is

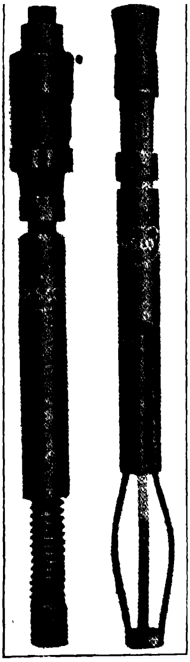


FIG. 200.—Types of tubing catchers. Left, Guiberson-Richards tubing catcher, Right, McKissick tubing catcher.

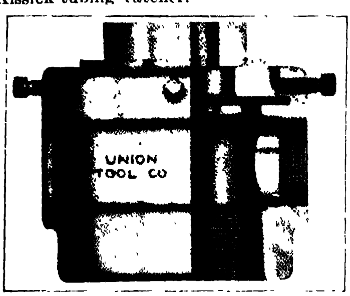


FIG. 201.—Common form of casing head.

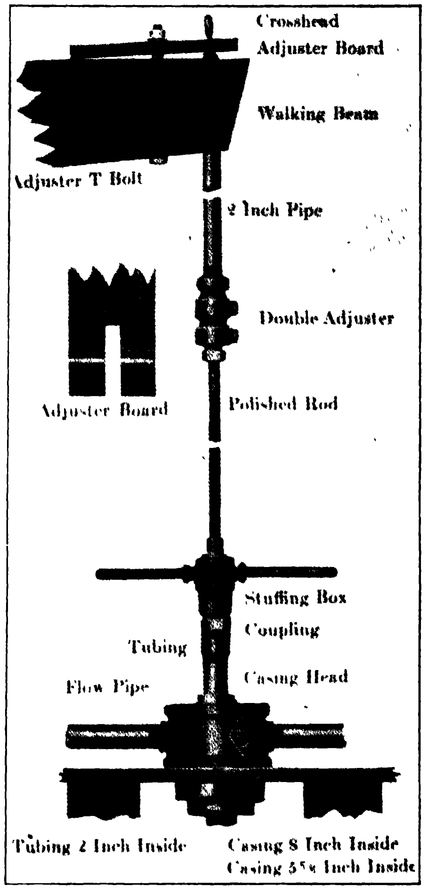


FIG. 202.—Illustrating power connections for beam pumping.

attached by means of an "adjuster grip" to a 2-in. pipe equipped at its upper end with a cross-head (see Fig. 202). The pipe passes through the temper screw slot in the end of the beam, and the cross-bar rests upon the upper edge of the beam. An adjuster board serves as a clamp to prevent the cross-head from moving in the slot. The adjuster grip

provides a means of taking hold of the polished rod at any desired point, regulation of the position of the plunger in the working barrel being effected by this means. For deep-well pumping, the temper screw is often left on the beam and used in place of the 2-in. pipe and adjuster grip, to connect the polished rod with the beam. This provides a ready means of adjusting the position of the pump plunger in the working barrel.

If the well is to be operated by a pumping "jack" with pull-line connections to some central power station, the triangular jack (see Figs. 217 and 219) is mounted at one side of the well and the polished rod connected directly to the angle overhanging the well. When multiple pumping is resorted to, the rig and derrick may be removed, though they are often convenient in facilitating repair work on the wells. The multiple system of pumping is to be described in greater detail in a later section of the present chapter.

Operation of the Oil Well Plunger Pump.—Assuming that the pump is to be operated from the walking beam, and that the rig and derrick have been left in position, the source of power will be either a steam engine of the type used for drilling purposes, a gas engine or an electric motor (see Chap. XIV). The prime mover is placed in the engine house and power is transmitted by belt to the band wheel, and through the instrumentality of the crank, wristpin and pitman, the walking beam imparts the necessary oscillating motion to the column of sucker rods.

For pumping purposes, the wristpin is usually placed in the second or third hole of the crank, giving a stroke of about 18 or 24 in.; occasionally a stroke of 30 in. will be used for pumping, and more rarely, 36 in., obtained by placing the wristpin in the fourth or fifth holes respectively. The speed of pumping ranges from 15 to 35 up-and-down strokes of the plunger per minute, depending upon the viscosity and density of the oil, depth of the well, submergence of the pump, presence of water, sand or gas, and other variables.

Assuming an average pumping speed of 20 strokes per minute and a 24-in. stroke, a 3-in. pump with a 2¾-in. plunger will have a daily theoretical capacity of about 353 bbl. per 24-hr. day; and under the same conditions a 4-in. pump with a 3¾-in. plunger will have a daily theoretical capacity of about 655 bbl. Although the pumping speed and length of stroke upon which these calculations are based are often exceeded in practice, when allowance is made for valve leakage and other inefficiencies, it is doubtful whether the average working capacities will ever exceed the figures given.

Plunger pump efficiencies are occasionally as low as 50 per cent of the theoretical plunger displacement. This is due in many cases to action of sand in preventing proper seating of the valves, or to leakage through the valves occasioned by wear. In the case of heavy viscous oils, the

pump must be operated at low speeds while well submerged, otherwise the oil will fail to completely fill the working barrel on the up stroke and the efficiency will fall off rapidly. On the other hand, gas associated with the oil frequently assists the pump so that efficiencies in excess of 100 per cent will apparently be obtained. Gas pressure may lift the valves and cause flow through the pump and tubing to the surface, even though the pump is in operation. Under the influence of gas pressure, a flow of oil may eject all or most of the oil from the tubing, so that a period of half an hour or more—in the case of a deep well—must elapse before oil again begins to flow from the lead line under the influence of the pump. Intermittent production is thus characteristic of some pumping wells as well as of most flowing wells.

There is no set rule governing the submergence of the pump but it is usually desirable to secure the maximum possible head of oil on the standing valve, without subjecting the pump to danger of "sanding up." Aside from its scouring action on the moving parts of the pump, loose sand present in quantity in the oil tends to settle over and about the valves, eventually preventing their proper action. Water in association with the oil and sand introduces a further complication, since sand is much less fluid in contact with water than when suspended in pure oil. If the working barrel becomes clogged with sand, it is often impossible to withdraw the plunger and valves, and the rods and tubing must be "pulled" together—a "wet" job, since the tubing is in this case filled with oil, which flows over the derrick floor and casing head as each "stand" of tubing is disconnected.

Some wells seem to produce more steadily if a moderate head of oil is maintained on the producing stratum, the fluid pressure so created serving as a stabilizing influence in restraining the flow of sand and gas. In other cases the well may be pumped practically dry without causing irregularities in operation. Only by experimenting with each individual well can the best combination of submergence, fluid level, length of stroke and pumping speed to give a maximum production, be determined. The operator usually finds it to his advantage to maintain uniform, continuous production, even though the quantity of oil raised per unit of operating time may be somewhat lower than is possible under conditions resulting in more spasmodic production.

When the oil is pumped too fast for the normal rate of well production, the flow will be intermittent and the oil will rise only part way in the working barrel, causing the plunger to "pound" against the oil on the down stroke, and encouraging the formation of gas pockets. In other words, if the pump is operated too rapidly, power is needlessly expended and the pump does not operate so efficiently.

Counterbalancing the walking beam is effective in producing a more uniform motion of the pumping mechanism, and results in an appreciable

reduction in power consumption. In deep wells the weight of the long column of sucker rods imposes a considerable unbalanced load on the well end of the beam, resulting in uneven motion of the engine, causing the rods to be picked up with a jerk on the up stroke, and resulting in extreme vibration and frequent rod breakage. Suspending a heavy counterbalance on the crank end of the beam largely overcomes this difficulty, giving a smoother pumping motion and incidentally reducing the consumption of power by from 8 to 22 per cent. The usual method of counterbalancing consists in suspending from the end of the beam near the pittman, a heavy block of concrete. A guide prevents the counterweight from swinging as the beam oscillates.

Reducing Wear on Pump Parts.—With the purpose of reducing and distributing wear on the moving parts of plunger pumps, a device known as the Sargent Rod and Plunger Rotor has been successfully used in some of the California fields. This consists of a mechanism attached to the polished rod and walking beam, which turns the sucker rods a fraction of a turn with each stroke of the beam. It is claimed that the use of this device greatly prolongs the life of valve seats, balls, plungers and liners, and that it is also effective in preventing sanding of the pump.

The Multiple System of Pumping

The maintenance and operation of a separate power plant at each well, which is necessary when pumping with the walking beam, is expensive. The horsepower of the engine or motor provided is usually greatly in excess of the actual power requirement for pumping purposes, and consequently it operates at greatly reduced efficiency. The excess power may actually be used only at rare intervals when repair equipment is necessary. If wells are operated by individual steam engines, the transmission of steam from the boiler plant to the wells occasions further losses. The repair work and attention necessary for a large number of steam or gas engines scattered over a property is also an expense of considerable magnitude.

When conditions permit, it is found to be more economical to operate a group of wells from one central power plant; and to accomplish this, a method of transmitting power from the central plant by a system of pull lines has been developed.* This is commonly called the "jack pumping-system," a triangular pumping "jack" being erected at each well to translate the horizontal reciprocating movement of the pull lines into the vertical reciprocating movement necessary for the operation of the sucker rods in the well.

* Barnes, R., Central power and jack-pumping plants for operating oil wells, *Thesis*, prepared under the direction of the author, May, 1917; later published in *Western Engineering*, 1917.

Multiple pumping is only feasible for comparatively shallow wells, being rarely employed when the wells exceed 2,500 ft. in depth. Furthermore, the wells must be fairly steady producers and not subject to sand "troubles," breakage of rods, tubing, etc., requiring frequent repairs. If the ground is fairly level and the wells are not more than 500 or 700 ft. apart, it is claimed that as many as 40 wells may be operated with pull lines from one central power; but in ordinary practice it is not usual to operate more than 25 wells in one unit, thus reducing the number that would be idle in case the power should fail. The wells should not be so remote from the source of power that elongation of the pull lines under tension would neutralize most of the motion; however, outlying wells are occasionally a quarter of a mile or more from the power station.

The central power plant is equipped with a prime mover which may be either a steam engine, a gas engine or an electric motor. The latter two are common, but it is unusual to find a central power operated by steam. The power requirements are fairly uniform, and efficiency rather than flexibility is the object sought. The prime mover drives a large horizontally supported band wheel, occasionally made of wood, though preferably made of steel. If an electric motor is used, it must usually be belted through a countershaft to the band wheel, in order to provide the proper speed reduction. The countershaft should be provided with a friction clutch so that the load may be thrown on the power after the motor or engine has been brought to full speed. The band wheel rotates once for each stroke of the pump in the well, so that normally the speed of rotation would be fom 15 to 20 revolutions per minute. Wells operated in multiple are generally pumped at a fewer number of strokes per minute than when operated on the beam. This is permissible, since the jack pumping system is seldom applicable until the wells have settled down to a relatively small production, and a normal sized pump is able to take care of the production of the well at a speed somewhat below the average for most pumping wells.

The band wheel of the central power plant is supported on a vertical shaft provided with a suitable thrust bearing, and adequately braced in all directions so that it rotates in a true horizontal plane. Either one, two or three eccentrics are attached rigidly to the band wheel shaft, so that they rotate one above another in horizontal planes. The eccentrics are provided with slip rings or hollow discs, supported on their outer rims in such a way that while the rings are held firmly against the eccentrics, the latter are free to turn in them. At equal intervals around the edge of the slip rings, are pins, hooks or links to which the pull lines leading to the various wells are attached. If two eccentrics are used, they are usually placed 180 deg. apart on the band wheel shaft (see Fig. 203). In some designs, the eccentrics are placed below the band wheel, and in others above. Suitable bearings placed in an iron frame, must of course be provided to support the revolving vertical shaft in its proper position.

It is clear from the construction described, that as the band wheel shaft revolves, if the slip rings are prevented from revolving with the eccentrics, they will be given an oscillating motion; and if rods or ropes are attached to the pins or hooks on the rims of the slip rings, each rope or rod will be pulled toward the center of rotation, a distance equal to the eccentricity of the eccentric, with each revolution.

A single eccentric power can handle from 6 to 20 wells with depths ranging from 1,000 to 2,000 ft., depending upon the gravity of the oil. From 14 to 25 wells may be pumped under similar conditions with a double-eccentric power.* Some of the heaviest types of steel band wheels with double eccentrics are designed to pump forty 1,500-ft. wells or twenty 2,500-ft. wells.

* LANGLEY, Pumping jacks. *Eng. & Min. J.*, vol. 109, p. 748, Mar. 27, 1920.

Occasionally powers are met with in which the prime mover is geared directly to the vertical shaft which revolves the eccentrics (see Fig. 204). Such powers are designed for somewhat lighter service than the band wheel type of power, but they operate in a similar manner.

Transmission lines, connecting the wells with the power, generally consist of steel rods or cables, though wooden rods are occasionally used. Often, old drilling

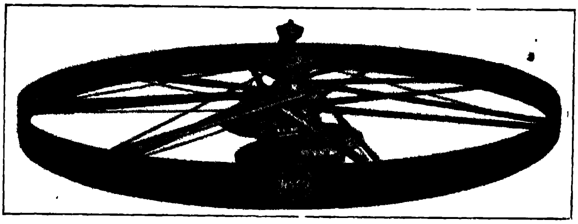


FIG. 203.—Double eccentric band-wheel type of power.

cable will be employed for this purpose, and is really preferable to new cable since most of the "stretch" has been taken out of it. If rods seem advisable, old sucker rods may be adapted to the purpose.

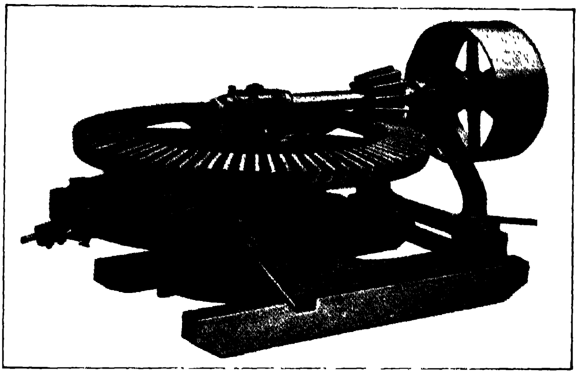


FIG. 204.—Single eccentric geared power.

Irrespective of cost, rods have the disadvantage of crystallizing and breaking, and are not as well adapted as cable where a long stroke and a fast motion are required. On the other hand, rods last longer than cables, and are better for long lines, since they have not as much elasticity and the length of stroke is therefore not shortened. In order to provide the necessary flexibility when rods are used, it is customary to insert short stretches of cable at intervals, otherwise the rods tend to "pound" or vibrate.

It should be noted that in this method of pumping, power is only applied to the pump on the up stroke. The weight of the sucker rods in the well will be sufficient to provide the necessary power on the down stroke and keep the transmission lines under moderate tension. The transmission lines are therefore always under tension, the tensile stress of course being greater on the up stroke of the pump than on the down stroke.

Transmission Line Supports.—Many ingenious devices have been contrived for supporting the transmission line and in providing for changes in direction of pull, or for

decrease or increase in the length of stroke. It is clear that in order to reduce friction and prevent wear of the transmission lines, they must not be permitted to drag on the ground or other stationary objects. Usually they are supported by what are called "hold-up posts" (see Fig. 205). These should be placed at approximately 25-ft. intervals in order to eliminate sag in the lines as far as possible. They often consist of 4- by 4-in. timber, one end of which is buried 4 ft. in the ground and securely anchored. The other end extends from 5 to 10 ft. above the ground, depending upon the topography. The post may support the cable or rod by passing the latter through a greased slot cut in the top of the post, or the line may be supported by a short cable suspended from a cross-bar nailed on top of the post. Near the power station, where there is considerable "side sweep" to the line, due to motion of the eccentric, the cable should be boxed in on top of the post.

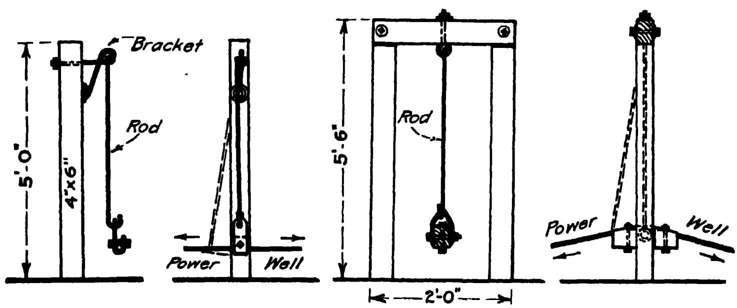


FIG. 205.—Hold-up posts for transmission line supports.

Instead of supporting the transmission line on stationary posts in this way, we may employ "rockers" or "pendulums." These devices are also made of timber, but the support, instead of being stationary, oscillates with the movement of the transmission line. In the case of the rocker (see Fig. 206), the pivot on which the post swings is placed at the bottom. In the case of the pendulum, it is placed at the top (see Fig. 207). This type of support is particularly useful in places where it is necessary to make a slight change in direction in a vertical plane, the rocker being employed on the brow of a hill and the pendulum in the bottom of a ravine. By such means, the transmission line may be made to conform more or less to the slope of the ground.

Occasionally it is necessary to change the direction of the transmission line in a horizontal plane, perhaps due to the necessity of avoiding some impassable obstacle or difficult topography. It may be also, in order to balance loads on the power, that a particular line will be carried out in some other direction from the power than that of the well which it is intended to operate. In such cases use is made of what is called an "angle" or "butterfly," a "hold-in swing" or a "horizontal rocker" (see Figs. 208, 209 and 210). The "butterfly" is the most satisfactory form of angle station, consisting of a triangular frame of timber, securely bolted together, held in a horizontal position and pivoted at one corner so that it may oscillate in a horizontal plane. The transmission line should enter and leave the butterfly horizontally. This can be accomplished by the use of either a rocker or a pendulum.

Another device commonly used when it is desired to lengthen the stroke, perhaps to compensate for the losses due to sag and stretch in the lines, is what is called a "multiplier" (see Fig. 211). The multiplier is also used to adapt the uniform stroke of the power to the variable conditions imposed by the requirements of different wells. By means of this device, the length of stroke of any transmission line may be lengthened or shortened to any desired extent. It will be noted that the multiplier

is somewhat similar in construction to the rocker or the pendulum, the essential difference being that in the case of the multiplier, the line connecting with the power is at a different distance from the pivot than the line connecting with the well. The lengths of stroke for the two lines will of course vary directly with their distances from the pivot. Multipliers may also be used for passing the transmission line over or under a road (see Fig. 212).

A "beam" is used for those rare occasions when the proper balancing of forces on the power requires that the direction of a transmission line be changed through an angle of 180 deg. (see Fig. 213). The wear on the swing post casting is heavy for this device and breakages are frequent.

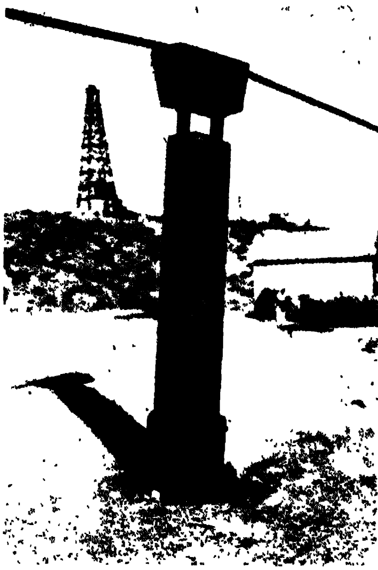


Fig. 206.—Rocker for transmission line support.

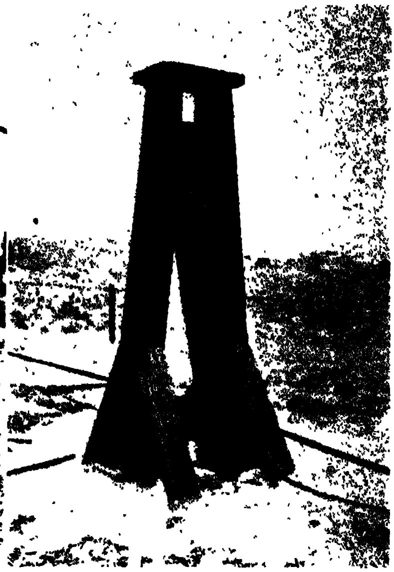


Fig. 207.—Pendulum for transmission line support.

It is often necessary to disconnect one well from the power for a time, and in order not to interfere with the operation of other wells on the same power, a device called a "throw-off" is provided. Rods are generally used to connect the power with the cable, and the cables are connected with the rods by means of large open interlocking hooks (see Fig. 214). Just back of the hook nearest the well on each line, a substantial hold-up post is provided, so that the base of the hook nearest the well almost touches the post at the end of the down stroke of the pump. By slipping a wooden block in between the post and the base of the hook at the end of the up stroke of the pump, the two hooks will disengage and the line may be disconnected from the power. A small hook is also used at the well to keep the line taut when it is disengaged from the pumping jack.

It may be arranged that one transmission line will operate several wells, by connecting branch lines through a butterfly with wells in different directions (see Fig. 215). In some instances a number of wells in a straight line are operated by a single pull line.

Pumping Jacks.—The pumping "jack" is the device at the well that transfers the horizontal, reciprocating motion given by the central power to the transmission lines, to the vertical reciprocating motion required by the sucker rods to actuate the pump

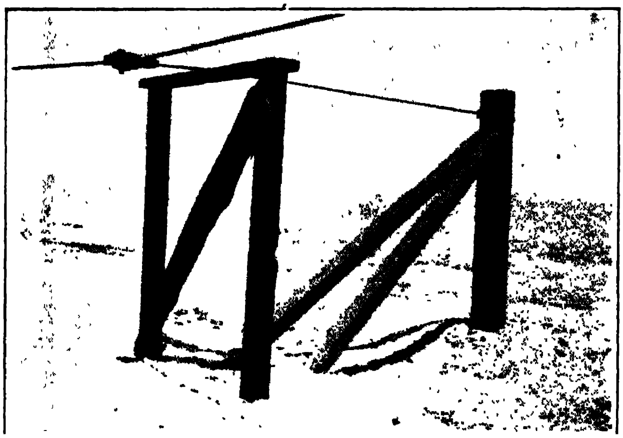
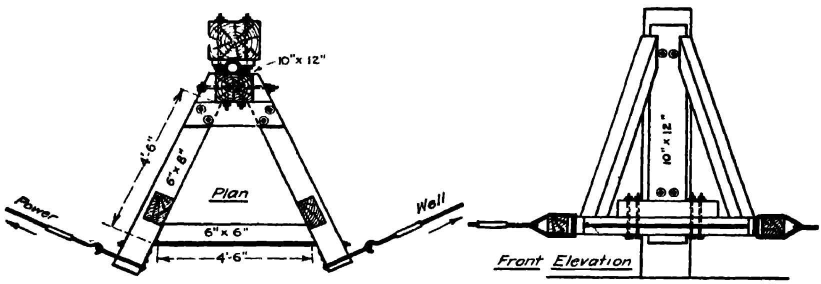


Fig. 208.—Hold-in swing for changing direction of transmission line.



(*After R. Barnes*).

Fig. 209.—"Butterfly" for changing direction of pull line in a horizontal plane.

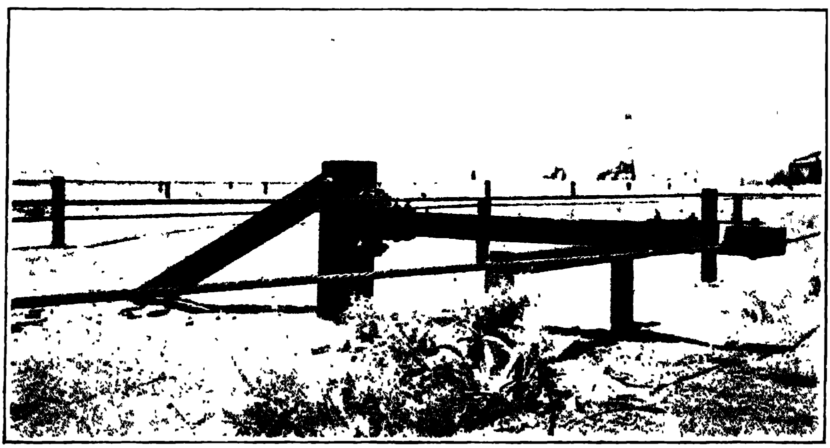


Fig. 210.—Hold-out rocker for changing direction of transmission line.

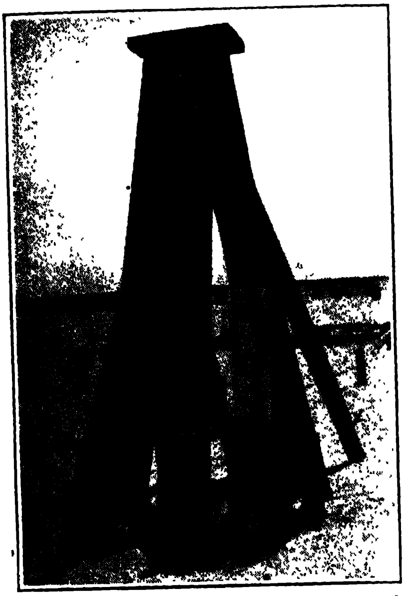


FIG. 211.—Multiplier for changing length of stroke of transmission line.

FIG. 212.—Multipliers used in passing transmission line over a road.

FIG. 213.—Beam for changing direction of transmission line through 180-degrees.

plunger. These jacks may be made either of timber or steel, preferably the latter. Those purchased from supply dealers are usually made of structural steel or steel pipe, while those made on the lease are often of substantial wooden members bolted together.

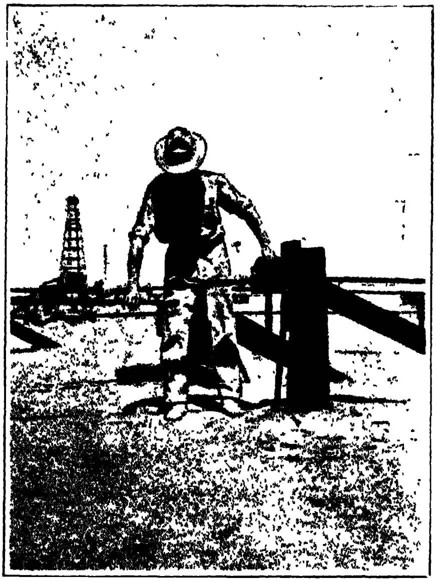
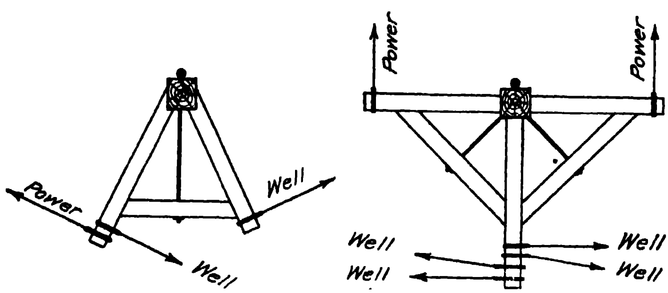


FIG. 214.—Illustrating use of throw-off post and hook

There are two principal types of steel jacks, one being known as the Jones and Hammond jack, and the other as the Oklahoma jack. The J. & H. jack is a simple triangular frame supported in a vertical plane and pivoted at one corner (see Figs. 216 and 217). The Oklahoma jack is a combination triangle and walking beam, generally



(After R. Barnes).

FIG. 215.—Illustrating use of "butterfly" in operating two or more wells with one transmission line.

made of structural steel forms, securely bolted to a rigid supporting timber frame (see Figs. 218 and 219). It is evident that there are a variety of ways in which these triangular frames may be pivoted, supported and connected with the power. An advantage of the Oklahoma jack is that the length of stroke may be varied by changing the position of support and connection of the various members.

Still another form of pumping jack occasionally met with is the "circle jack." This consists of a semi-circular timber frame, mounted on a suitable support and pivoted at the center of the circular arc. It is so suspended that the arc of the frame is over the center of the well, and at some distance above, say 8 or 10 ft. (see Fig. 220).

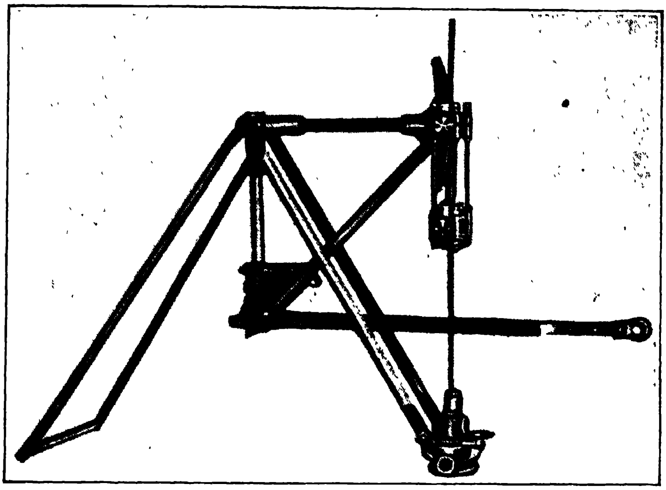
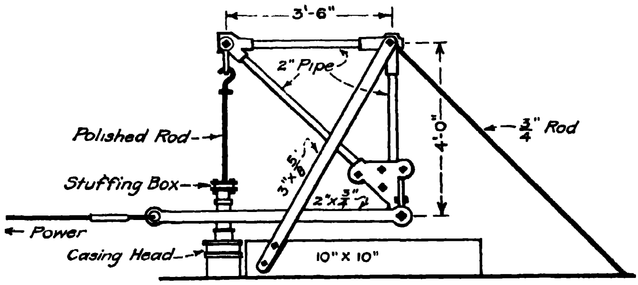


FIG. 216.—Jones and Hammond steel pumping jack.

The transmission line is carried over this circular frame and down to the connection with the polished rod. The chief advantage of this form of jack is that it exerts a straight upward pull on the polished rod at all times. Other forms of jacks, as well as the ordinary walking beam connection used when pumping on the beam, develop a



(*After R. Barnes*).
FIG 217.—Jones and Hammond jack.

considerable side thrust, as the point of connection with the power describes an arc instead of moving up and down vertically. While this side thrust is more or less absorbed by the "spring" of the polished rod, it nevertheless results in certain friction losses, and occasions wear on the polished rod stuffing box, and causes swaying of the tubing and casing head connections.

The Push-and-pull System of Multiple Pumping.—The push-and-pull system of multiple pumping is very similar to the method just described, except that a somewhat

different form of power is used and the transmission rods are of wood and of sufficient cross-section to sustain moderate compression as well as tension. The power, instead of being equipped with an eccentric and slip ring to develop the necessary reciprocating movement of the transmission lines, utilizes a crank and connecting rod to drive the

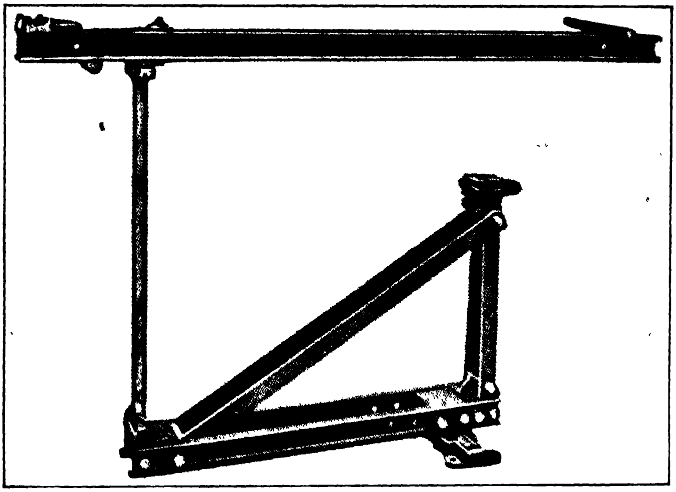
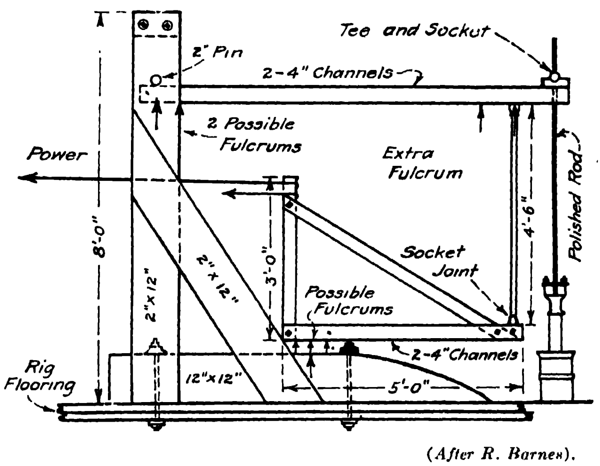


FIG. 218.—Oklahoma type of pumping jack.

rods which are attached to the circumference of a horizontally supported wheel or rotary table (see Fig. 221). This form of power is best adapted to the operation of a small number of shallow wells, and is now almost obsolete except in some of the eastern United States fields. Western operators generally prefer the slip ring type of power, which is more substantial, has greater capacity and is more flexible in its application.



(*After R. Barnes*).
FIG. 219.—Oklahoma type of pumping jack.

Unit Pumping Installations.—Wells drilled with the rotary rig, if too deep for jack pumping, will ordinarily have to be equipped, on completion, with the regulation band wheel, crank, pitman and walking beam

of the standard cable rig, a somewhat expensive installation if the rig is not initially designed for it. It is primarily because of this necessity that operators in deep territory in the California fields prefer the combination rig. However, there has been developed a type of "unit power"

FIG. 220.—A circle jack.

adaptable to wells of moderate depth, which obviates the necessity of installing the cumbersome standard equipment.

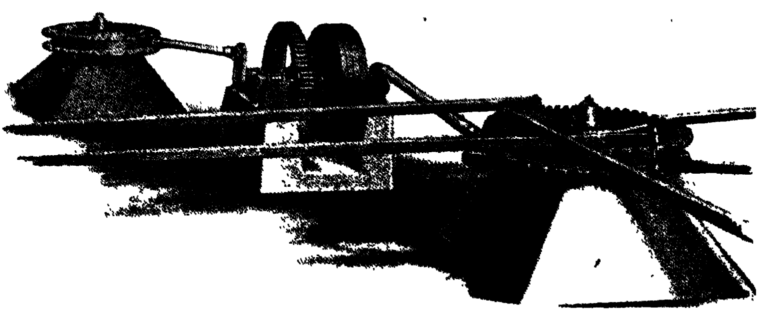
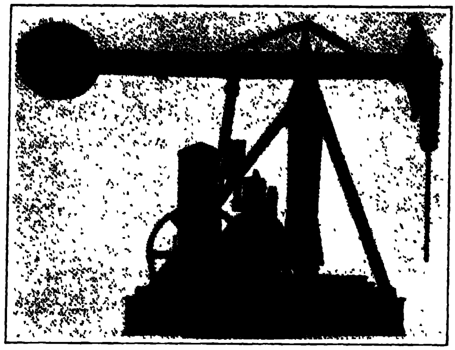


FIG. 221.— "Push-and-pull" type of pumping power.

A well-known type of self-contained pumping unit, intended for pumping a single well, is illustrated in Fig. 222. This outfit is made entirely of steel and is equipped with a balanced steel walking beam,

driven by a gas or gasoline engine or an electric motor, connected with the beam through gearing and a crank-driven steel pittman.

Still another type of pumping unit is commonly known as a "steam head." This consists of a simple, single-cylinder steam engine supported with the cylinder in a vertical position directly over the well. The end of the piston connects with the polished rod on which the sucker rods are suspended. By proper valve adjustments, the steam supply can be so



(Oil Well Supply Co., Pittsburgh, Pa.)
FIG. 222.—"Oilwell" pumping unit.

regulated on the up and down strokes that a uniform motion is produced without shock or jar. This device may also be operated by compressed air or by high-pressure gas. The steam head is not extensively used, and is suitable only for shallow well service.

Balancing the Load on the Central Power in Multiple Pumping.—It is apparent in the design of a jack pumping plant, that power may be saved and operating difficulties avoided, if the load on the central power is approximately balanced. That is, the load on the eccentrics should be so adjusted that the power requirements are practically constant throughout a complete revolution of the band wheel. This necessitates a close study of the load factors imposed by the different wells and their directions from the power station.

Knowing the depth of each well, the size of the tubing and sucker rods and the gravity of the liquid to be pumped, the weight upon the plunger of the pump can be computed. This weight must be lifted during each stroke through a distance corresponding to the length of the stroke of the plunger. From computation of the work so accomplished with due allowances for frictional losses and other inefficiencies of the system, the power necessary to pump each well may be estimated.

If we assume that there is no motion in the system, the weight upon the pump plunger becomes a static load. The vertical force represented by this load is changed, by means of the pumping jack, to a horizontal

force; and since the load on each well of a group will vary due to differences in depth, the horizontal forces representing these loads will be different for each well. When the central power is set in motion, friction increases the load in one direction and decreases it in the opposite direction. This friction is due to a variety of causes, among which may be mentioned friction at the pump, friction at the pumping jack and friction in the transmission line and its supports. We may evaluate these various forces, either on the basis of mathematical computations, or by actually measuring them and the power requirement for each well is thus determined.

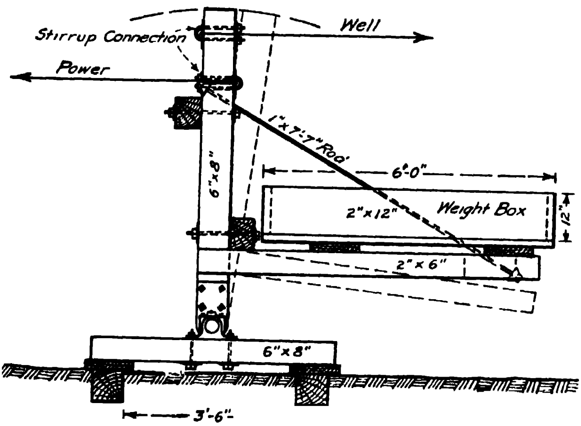
We may construct a map diagram on which these forces are represented graphically by straight lines of varying length drawn to scale; and if we assume a position for the power, it will be possible to scale off these distances on the map from the position selected, in the direction of the wells the power requirements of which they represent. We may then resolve these forces by means of a force diagram, determining the direction and magnitude of the resultant force. By repeated trial in this way, the point may be found on the map where the resultant of all forces is zero, and this should be the site selected for the power station.

It is evident that in the case of a double-eccentric power, if there are a sufficient number of wells, it is possible to readjust the connections of the transmission lines on the eccentrics, so that slight inequalities in loading may be compensated for. Thus, if the load in one direction from the power seems to be greater than in other directions, we may change one of the transmission lines on that side to the other of the two eccentrics. Its load will, then, in effect be taken up as though it were actually on the opposite side of the power. This is true because the two eccentrics are placed 180 deg. apart on the band wheel shaft. In other words, while the pumps in wells on one side of the upper eccentric are on the up stroke, those in wells on the same side of the power connected with the lower eccentric will be making their down stroke. In any case, some adjustment of the loads will always be necessary after the plant is placed in operation. Where a motor is used for power, the balancing of well loads may be assisted by placing an ammeter in the motor circuit and noting the position of the eccentrics when the motor takes its maximum load.

In general, when the topography is rough and the wells are in a compact group, it will be found advisable to choose a suitable position for the central power plant, as near the geographical center of the group of wells as possible. There must be sufficient clear and level space all about the power, however, to permit of making suitable take-offs from the power rods, and for the placing of throw-off posts.

It will often happen that the zero-resultant position indicated on the map with the aid of the force diagram, will be found quite unsuited to

the purpose because of topographic difficulties. In such case it is necessary to select the nearest suitable site and make such adjustments as are necessary in the load balance to counteract the influence of misplacement of the power station. This may necessitate a change in the direction of one or more of the transmission lines, leading it off from the power in a direction which will bring about compensation of the load, and later introducing another change in direction to bring the line to the well. These changes in direction are accomplished with the aid of a butterfly



(After R. Barnes).
FIG. 223.—Balance-bob for balancing loads on power.

or angle station as described above. In other cases a balance bob (see Fig. 223) may be constructed in the opposite direction from the resultant of the well forces, loaded with rocks and heavy scrap metal, connected with the power by a separate transmission line and operated as though it were an additional well. Balance bobs may also be necessary at or near the well in cases where the wells are so shallow that the rods are not heavy enough to keep the transmission line under proper tension on the down stroke of the pump. Operation of a balance bob of course occasions an increase in the power requirement on one stroke, but most of the power stored in it is recovered on the opposite stroke.

It should be remembered that all of these forces operating on the power are of mutual influence. The weight of the descending sucker rods in wells on the north side of the power will actually help to pump wells on the south side of the power. The power necessary to operate a well by the multiple system is therefore considerably less than is necessary when the wells are operated by individual engines or motors. Often when wells are pumped by means of individual steam or gas engines at each well, an engine of from 20 to 30 hp. will be used, frequently the one used in drilling the well. This is usually far in excess of the requirement

for ordinary pumping. A rough determination of the actual amount of power needed to pump a well, arrived at by averaging conditions at a large number of wells of varying depths in the California San Joaquin Valley fields, indicated an average of about 7 hp. For pumping 1,000-ft. wells in multiple from a central power, the power requirement may be reduced to as little as 2 or 3 hp. per well in many cases.

Because of the lower operating cost, most producers adopt the multiple pumping system in operating their wells if it is feasible to do so, and examples of this practice are to be found in most shallow fields (depths up to 2,500 ft.) where the wells have attained fairly uniform operating conditions. On one property in the Kern River field of California, 288 wells are pumped with jacks. On another property in the same field, in 1912, 22 wells averaging about 1,000 ft. in depth and producing 15°Bé. oil, were pumped by means of a motor-driven power at a total power cost of about $6 per day. Three such outfits displaced eight 70-hp. boilers and reduced the labor from 35 to 21 men. Practically all of the wells in the Summerland field of California are pumped with jacks. The wells are here drilled from piers extending out from the shore of the Pacific Ocean. All of the wells on each pier are pumped by a single transmission line from a power located on shore. On one property in the Midway field, California, 46—1,200-ft., 30-bbl. wells are pumped by three electrically driven powers. A test made soon after the plant was installed showed a power consumption of 2.45 hp. per well and a cost for power of only $.438 per well per day (electric power at this time cost only 1 cent per kilowatt-hour). It is said that sand troubles on these wells were much reduced after the multiple system was installed, due to its more uniform speed and control. When these same wells were pumped on the beam by individual steam engines, the cost of power averaged $1.05 per well per day, and the average horsepower per well was 5.85. These figures indicate a saving of 56 per cent by the use of the multiple pumping system.

In general, for California jack pumping practice, it has been found that the average consumption of power, using electrically operated powers, ranges from 15 to 40 kw.-hr. per well per day, or 1.5 to 2.5 kw.-hr. per barrel of fluid pumped. In 1917, a jack pumping plant in the Belridge field of California, of sufficient capacity for the operation of 21 wells, cost about $8,000 to install, or approximately $380 per well.*

Repairing Well Pumping Equipment

From the foregoing description of well pumping equipment, it will be apparent that a variety of occurrences may prevent satisfactory operation of the pump, necessitating repair work. Most producers find it

* Barnes, R., Central power and jack pumping plants for operating oil wells, *Western Eng.*, 1917. (*Thesis*, University of California, 1917.)

necessary to employ one or more repair crews of three or four men each, who are continually engaged in making necessary repairs on the pumping wells. A common difficulty is occasioned by valve leakage as a result of wearing of the balls and seats. Sand is especially destructive in this regard, valves and seats lasting but a few days in extreme cases when much sand passes through the pump. The difficulty experienced as a result of accumulated sand clogging the working barrel and preventing action of the valves, has already been mentioned. Worn plungers, cup

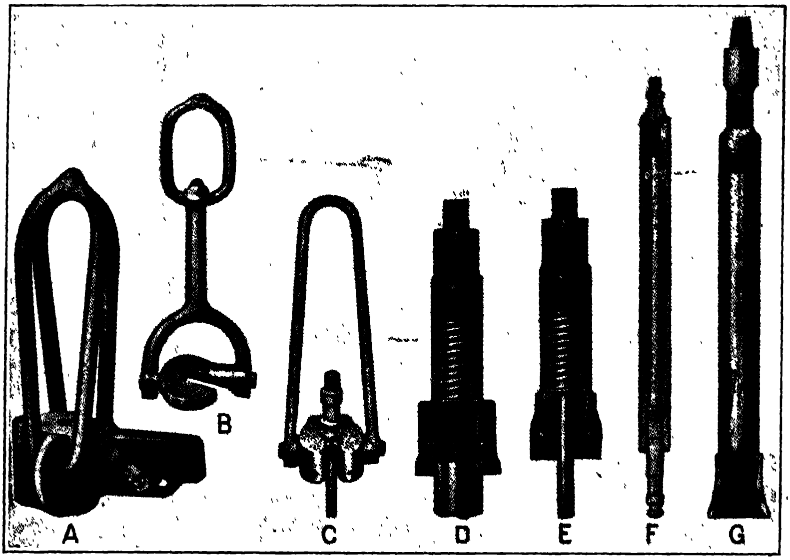


FIG. 224.—Sucker rod and tubing elevators and fishing tools.
Sucker rod elevators: *A*, Fair type; *B*, swivel type; *C*, Dunn's patent. National combination socket: *D*, catching pin; *E*, catching rod; *F*, Burrough's sucker rod socket; *G*, tubing spear.

leathers and working barrels will cause leakage of oil around the plunger, with reduced efficiency of pumping. Sucker rods often break in the well, either as a result of "sanding up" of the pump, or because of defective screw joints or welds, or by crystallization or fatigue of the metal. Rubbing of the rods on the tubing occasions wear on both, holes being sometimes worn in the tubing so that oil leaks out, while the rods become so worn at the joints that they fail to resist the tensional strain put upon them. Wear on the rods and tubing is also accentuated by the presence of sand. Occasionally the tubing will pull apart in the well, either as a result of defective joints, unusual strain or wear.

Replacing Worn Pump Parts.—When reduced efficiency of the pump indicates that the valves and seats are in need of replacement, the polished rod is detached from the walking beam or pumping jack, the top of the stuffing box is removed together with the packing rings, and the sucker rods are "pulled" with the aid of a sucker rod elevator (see Fig. 224). The rods are generally disconnected as they are withdrawn from

the well, in "stands" of about 60 ft. in length. The rods are too flexible to permit of standing them on end in the derrick, and they are customarily laid horizontally on the floor of the derrick or along the plank platform leading from the derrick to the engine house. A skilled well-pulling crew of three men can rapidly accomplish the manipulation of the elevators, wrenches and power controls necessary to remove the rods from the well and disconnect them. On emerging from the well, the pump plunger and valves are washed with distillate and carefully examined. If the balls and seats are worn, they are replaced with new ones, or in some cases, simple reversal of the seats will give renewed life.* The plunger is also calipered and otherwise examined for signs of wear.

If the plunger is worn, the tubing and working barrel should also be "pulled." This involves further delay while the tubing is withdrawn, with the aid of the bull wheels or calf wheel and tubing elevators (see Fig. 104), and uncoupled in 3-joint stands. These are stood on end in one corner of the derrick. When the working barrel has been detached from the tubing and cleaned, the plunger is tested in it for clearance. If the condition of the plunger and barrel warrants, the pump should be sent to the shop for refitting of a new liner in the barrel, or a new plunger, or both.

In replacing the pump in the well, the working barrel is screwed to the lower end of the first stand of tubing (sometimes with a joint or two of perforated tubing as an anchor below the foot piece), and lowered with the elevators, coupling the stands together, "setting up" the joints firmly with the tongs, until the working barrel reaches the desired depth. The plunger and valves connected on the end of the first stand of sucker rods are then lowered and the column of rods similarly assembled and lowered until the plunger enters the working barrel. The rods must be lowered until the standing valve enters its conical recess in the foot piece, driving the standing valve lightly into place by allowing the plunger nut to strike the top of the lower cage. The rods are then raised sufficiently to prevent the plunger from striking the standing valve on the down stroke of the pump, and the adjuster grip is attached to suspend the plunger at the desired depth. The polished rod stuffing box is then packed and adjusted, the lead line connections are made and all is again in readiness for pumping.

"Pulling" a Pump Which Has Become Clogged with Sand.—If the pump "sands up," or accumulates sand within the working barrel and about the valves to such an extent that pumping becomes impossible, the plunger and valves often cannot be pulled on account of the sand settling above the plunger. In this event, the working barrel and tubing must be raised together. After disconnecting the power, an effort is first made to remove as much of the column of sucker rods as possible, by applying a wrench and turning the rods until some joint unscrews. The column of rods may part anywhere, perhaps not at all, depending upon the security of the joints. If the column of rods parts somewhere in the well, the rods so unscrewed are withdrawn, from the well, uncoupled and preparations made for "pulling" the tubing. The tubing has probably been left nearly full of oil, so that as it is uncoupled into stands, the oil flows out, and provision must be made for draining it away to a near-by sump. It is a dirty job at best for the repair crew. When the upper end of the parted column of rods reaches the surface, another section of the column of sucker rods is unscrewed and withdrawn, thus alternately uncoupling the rods and tubing until the pump reaches the surface. After cleaning it of accumulated sand, the pump, rods and tubing are replaced as described in the preceding section. While the pumping equipment is out of the way, the accumulated sand in the bottom of the well may be removed by bailing, thus preventing an immediate repetition of the difficulty.

* Valves and seats may be reground if not too badly worn, by grinding on a glass plate with powdered carborundum and oil. The ball is rolled on the glass plate, describing a figure 8, while keeping the seat pressed down on top of the ball and the latter pressed against the plate.

Repairing Parted Sucker Rods.—The sucker rods often part in the well, either as a result of extreme tension, a defective coupling, wear or unscrewing of a joint by vibration. In this event, after the upper portion of the column of rods has been withdrawn, a fishing device, known as a "sucker rod socket," is lowered through the tubing on the sand line or on a string of sucker rods, until the upper end of the parted column is engaged (see Fig. 224). The parted column of rods is then hoisted with the plunger and valves until the upper end reaches the surface. The broken or defective rod is then replaced with a new one and the rods and pump again lowered into working position.

Repairing Parted Tubing.—Tubing sometimes becomes so worn by abrasion of the sucker rods that it parts in the well under the influence of its own weight, or as a result of the vibration of the rods. If the pump "sands up" so that the plunger is held fast in the working barrel, the full force of the power applied to the rods is exerted on the weakened cross-section of the tubing, causing bending or rupture. The column of tubing sometimes parts by unscrewing of a collar as a result of vibration. To repair parted tubing, the rods and pump plunger are first withdrawn, then the upper end of the parted tubing. A "tubing spear" is next lowered on the drilling cable or a second string of tubing, to fish for the detached tubing (see Fig 224). When the spear has taken hold, the parted column is lifted to the surface, the parted joint replaced and the tubing, rods and plunger again lowered into working position.

Well Pulling Equipment.—The power required for repair operations is greater—perhaps double—that necessary for ordinary pumping service. Furthermore, the prime mover must be somewhat flexible in speed and torque, while pumping requires a fairly uniform expenditure of power. If the well is equipped with its own individual engine or motor, it will ordinarily be used also as a source of power in conducting repair work. Hence, the prime mover selected should be one capable of considerable variation in speed and power output. The two-speed electric motor is well adapted to this dual service and is preferred by most operators to the gas engine or steam engine, where electric power is available, because of its low operating cost (see page 448).

Though unnecessary for the pumping of the well, many producers prefer to leave the cable drilling rig practically intact, to facilitate the occasional necessary repair work. The sand reel is necessary for running the bailer in cleaning out the well. The bull wheels are useful in raising or lowering rods and tubing. The walking beam is generally utilized in operating the pump, but in repair work it is also necessary in operating the cable drilling tools during procedure necessary in redrilling operations, drilling out sand "bridges," etc. Though it is perhaps seldom necessary to do any heavy pulling, if shifting or caving sands part the liner or oil string the calf wheel will be a useful accessory in making the necessary repairs. It will be especially important to leave the drilling rig intact if the well is a deep one, say in excess of 2,500 or 3,000 ft.

For shallow well service, particularly when the wells are operated in multiple, with the aid of jacks, the drilling equipment is frequently removed from the wells and much of the rig is dismantled. Perhaps all that will be left will be the derrick and bull wheels, and in many instances

even these will be removed. In this case, it will be necessary to assemble portable well-pulling equipment at the well, when repairs are necessary.

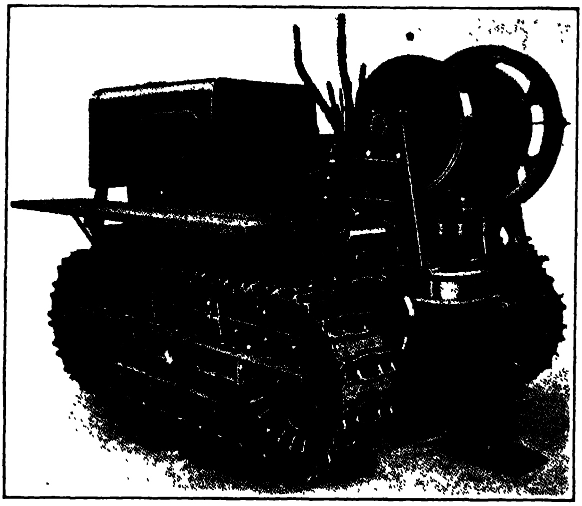
For this service, several types of compact and easily transported well-pulling machines have been developed, and have found extensive application on properties using the multiple system of pumping. In some cases they are equipped with gasoline engines, and in other cases with electric motors, power connections being provided at each well in the latter case. They are usually mounted on wheels or on a caterpillar tractor,

FIG. 225.—Well pulling machine mounted on motor truck.

and may be moved about by horses, or, in the case of gasoline-driven machines, under their own power. The machine is usually equipped with a geared hoist, on which may be wound the cable used in pulling the rods and tubing. A collapsible mast is often carried, which can be erected over the well as a substitute for the derrick.

One of the most successful types of pulling machines for shallow and moderately deep wells is mounted on the bed of a 3-ton motor truck, and consists of a chain-driven hoist which can be operated from the main drive shaft of the truck (see Fig. 225). A suitable clutch permits of transmitting power from the truck engine, either to the rear wheels for traction, or to the hoist for pulling purposes. The hoist may have as many speeds as the truck gears provide. The Mack truck illustrated in the photograph is able to lift about 1,000 ft. of 3-in. tubing in high gear, while the lower gear ratios have a much higher capacity.

Another type of portable pulling machine intended for use where the derrick has been removed is illustrated in Fig. 226. The Franklin machine is mounted on a small caterpillar tractor, and is readily moved about the lease under its own power. The speed and pulling capacity are governed by the number of lines used in the hoisting block, but the lifting capacity ranges from 4,500 lb. with a single line to as much as 36,000 lb. with 9 lines. It can handle about 2,000 ft. of sucker rods without difficulty, and may be used also for bailing. Power is furnished by a four-cylinder, four-cycle, heavy-duty tractor gasoline engine. The complete machine weighs about 10,800 lb. This machine may also be equipped with a tubular braced mast for use on wells from which the derricks have been removed.



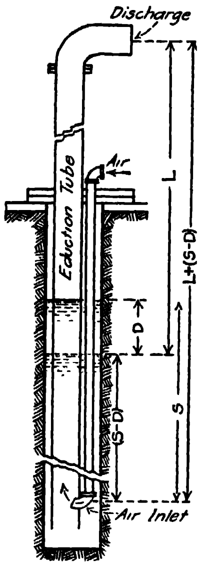
(Franklin Tractor Co., Greenville, Ohio).
FIG. 226.—Franklin well-pulling machine.

Numerous examples of portable pulling machines utilizing electric power are to be found in use in the oil fields. The usual arrangement consists of a motor-driven hoist mounted on a substantial 4-wheeled truck. A high-torque motor with variable speed is desirable for pulling, a controller being provided to control the motor while a suitable friction clutch, or gearing, drives the hoisting drum.

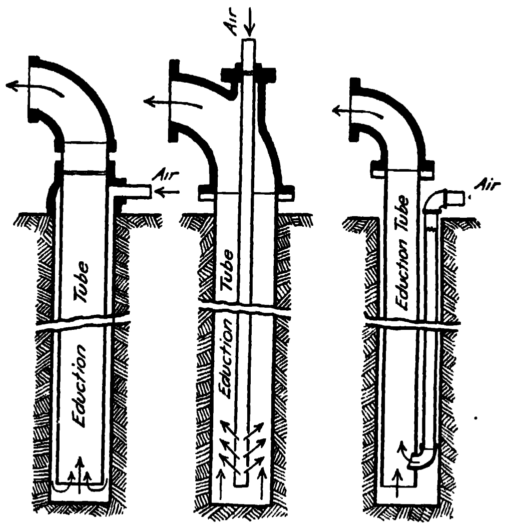
Pumping Oil from Wells with the Air Lift

Another method occasionally used in pumping oil from wells involves use of compressed air and the air lift. This is a device that has been widely employed in the pumping of water, and to some extent also, of oil, which depends upon the buoyant effect upon liquids confined in a restricted tube, resulting from aeration with compressed air. In applying the

method to the pumping of oil, compressed air is discharged under pressures ranging from 100 to 500 lb. per square inch, into the lower end of a column of casing or tubing partially submerged in the well fluid. The air, in rising through the column of pipe, becomes more or less entrained in the oil and, expanding as it rises, decreases the density of the fluid. The lower end of the discharge pipe being submerged in the well fluid for a depth of from 30 to 50 per cent of the total lift, the hydrostatic head of the aerated fluid within the pipe is opposed by that of the denser fluid without, and



(*After Ingersoll-Rand Co.*)
FIG. 227.—Illustrating relation of variables in air-lift formulae.



(*After E. M. Ivens, Trans. Am. Soc. Mech. Engrs.*)
FIG. 228.—Methods of piping oil wells for air-lift pumping.

the fluid within the pipe therefore rises. In Fig. 227, the air lift nozzle is submerged to a depth S below the fluid level within the well. This is the "static submergence." After pumping is begun, the fluid level will fall a distance D before it again reaches equilibrium, and the operating submergence becomes $S - D$. The operating lift or pumping head is L. The operating submergence, $S - D$, divided by the depth of the air inlet below the level of discharge, $L + (S - D)$, is called the "percent submergence." The head D, is the hydrostatic equivalent of the pressure necessary to cause fluid to flow into the well in amounts equivalent to the operating capacity of the lift. Assume static conditions with oil standing in the well to the height S above the air inlet. It is clear that in order to inject air into the well fluid, we must compress the air until its pressure exceeds the hydrostatic head at this depth. The minimum necessary starting pressure we may

calculate as $S \times 0.434 \times d$, in which S is expressed in feet and d is the specific gravity of the fluid to be pumped. To this must be added sufficient pressure to overcome friction losses in transmission. As the air is injected into the fluid within the discharge pipe, the density of the fluid within the pipe is reduced in comparison with that on the outside. Hence, the depth of fluid, S, without the pipe, balances a somewhat longer column of fluid within, and the fluid on the inside rises. As it does so, the air continues to expand, and the density of the fluid within the discharge pipe is further reduced until there is a sufficient elevation of the aerated fluid to cause it to overflow at the surface. The effectiveness of this process is somewhat reduced by rising of the air through the oil, but this is resisted by the viscosity of the oil, and by the restricted cross-section of the discharge pipe. After oil has begun to flow to the surface and a balance in forces is obtained, the fluid level within the well drops to depth L below the point of discharge, and the air pressure, in pounds per square inch, necessary to maintain flow, is reduced to $(S - D) \times 0.434 \times d$.

The volume of air necessary to produce flow depends upon the characteristics of the fluid pumped, that is, upon its viscosity and the extent to which the air can slip through the column of fluid without doing useful work, and also upon the submergence and efficiency of the air-lift nozzle. For calculating the volume of air necessary in pumping water, with lifts up to 500 ft., the following formula proposed by E. A. Rix* may be used:

$$V = 0.8 \frac{L}{C \cdot \log \frac{(S - D) + 34}{34}}, \text{ in which}$$

V is the volume of air necessary per gallon of water pumped, and C is a constant. L is the total lift and $(S - D)$ is the operating submergence (see Fig. 227). Values of C for different values of L are given in Table XXXII.†

TABLE XXXII.—VALUE OF CONSTANT, C, FOR USE IN RIX' AIR-LIFT FORMULA‡

Lift in feet, L	Constant
10 to 60 ft. inclusive	245
61 to 200 ft. inclusive	233
201 to 500 ft. inclusive	216
501 to 650 ft. inclusive	185
651 to 750 ft. inclusive	156

‡ Pumping water with most efficient submergence.

* RIX, E. A., Air-lift pumping of fluids, *Oil Industry*, vol. 3, pp. 4–11, June 15,1910.

† From Ingersoll-Rand Machinery Company's Catalog no. 76.

It must be noted that this formula is intended only for use in computing the volume of air necessary in pumping water. Though oil is more viscous, resulting in better occlusion of the air bubbles than is possible with water, a greater volume of air is found to be necessary to overcome the pipe resistance to flow. Because of the variable flow characteristics of crude petroleums, no formula such as the one given above for water has yet been devised for calculating the volume of air necessary. Practical results obtained in pumping oil from wells with the air lift however, have indicated that the equivalent of from 1 to $1\frac{1}{2}$ cu. ft. of free air per gallon of fluid delivered, or about 11 volumes of free air to one of oil, must be provided. As indicated in the formula given above, this will be influenced by the lift, L, and by the submergence ($S - D$). Best results in the pumping of oil are said to be obtained with submergence of between 30 and 40 per cent, but this varies somewhat with the lift as indicated in Table XXXII, giving proper submergence for varying lifts in pumping water. A submergence of even 30 per cent is not always feasible if the wells are deep and the fluid levels are low. If the submergence is insufficient, the efficiency rapidly falls off, as much as 50 or 70 volumes of air to one of fluid pumped being required in some cases.

In estimating the necessary size of the discharge pipe, it is well to assume an average velocity of flow of from 6 to 8 ft. per second, or about 12 to 18 gal. per minute, per square inch of cross-section. Too large a pipe allows undue "slippage" of the air through the fluid, while too small a pipe results in an ejector effect within the pipe, leading to spasmodic action.

Gas accompanying the oil assists in the operation of the air lift by diminishing the required air pressure. It is claimed, however, that there is an excessive volumetric consumption of air by slippage when gas is present. Wells of the same diameter and depth may thus require different pressures, because of differences in the quantity and pressure of the gas. In order to secure the full advantage of such gas as the well produces, it is customary to place a packer between the tubing and casing above the oil level, thus forcing all gas to follow the oil.

Air-lift Installations.—Commonly used methods of piping wells for operation with the air lift are illustrated in Fig. 228. That in which one tube is placed within another is probably most used. The outer tube is conveniently about 4 in. in diameter, extends nearly to the bottom of the well and is open at the lower end to admit the oil. This is the eduction tube. Into it is lowered the smaller column of tubing, about 1 or 2 in. in diameter, which serves to conduct the air to the level at which it is discharged into the oil. Suitable connections are made at the casing head to pass the air line into the eduction pipe through an oil-tight joint, and the eduction pipe is connected through the lead line to the storage tank. A stuffing box type of casing head (see Fig. 229) is preferable to the ordinary kind in order to prevent any movement of air, gas or oil between the casing and the eduction pipe. It is customary to have a pressure gage on each side of the valve which controls admission of air to the

capable of producing more oil than this, some other means of lifting the oil must be adopted, and here the air lift is of value because of its large capacity. Under favorable conditions the air lift, operating through only a 3-in. eduction tube, is capable of lifting from 2,000 to 5,000 bbl. per day, depending upon the lift and submergence. No other known method of pumping, applicable to oil wells, will approach the air lift in capacity.

One of the great advantages of the air lift is its ability to handle sand. The moving parts of the oil well plunger pump are rapidly worn in lifting oil carrying large amounts of sand. The air lift has no moving parts and is capable of lifting oil containing as much as 50 per cent of sand in suspension. It therefore finds what is probably its most useful purpose, in pumping wells afflicted with sand "troubles." Wells incapable of operation with the plunger pump because of sand incursion, have been successfully operated with the air lift and sand prevented from accumulating in the well to the detriment of oil production.

The first cost and operating cost of air lift equipment will be comparatively high, but its efficiency will compare favorably with that of the plunger pump. Over-all efficiencies as high as 40 per cent are possible in air-lift pumping.

An important disadvantage of the air lift in pumping oil is its tendency to form emulsions, if water is present. Conditions attending the injection of the air into the oil, together with the resulting agitation of the fluid, are favorable to the formation of emulsified mixtures which are often difficult and costly to separate. The cooling effect of the expanding air upon paraffin oil will sometimes result in accumulation of quantities of solid wax, which tends to clog the well piping and perforations through which the oil enters.

It will be evident that the air lift has a rather limited field of application, being confined to wells which maintain a sufficiently high fluid level to secure proper submergence. The well, furthermore, must be capable of producing enough fluid to keep the lift in continuous operation, for the efficiency rapidly falls off when action is intermittent, and placing the lift in operation after a period of idleness is troublesome because of the necessity for increasing the pressure.

Typical Air-lift Oil Pumping Installations and Operating Results.—The first recorded application of the air lift in pumping oil wells was in the Russian fields of the Baku region in 1899. Operation of wells in these fields was complicated by the incursion of large quantities of unconsolidated sand, which in the bailing process of extraction commonly used, is troublesome. Wells which only produced a few hundred poods of oil per day by bailing, were increased to as many thousand through use of the air lift, chiefly due to ability of the lift to extract the sand and maintain a lower fluid level.[11] The wells in this field offer exceptionally favorable conditions for the operation of air lifts, since the depths are not great (1,100 to 2,000 ft.) and the fluid levels are high (lifts are commonly 400 to 700 ft.).

A. B Thompson[8] records the results of one test in which a 4-in. pipe was used as an eduction tube, with an air pipe 2½ in. in diameter. The depth of the air

connection was 1,464-ft., the submergence 694 ft. and the lift 770 ft. The working air pressure was 300 lb. per square inch. The volume of air used was equivalent to 150 cu. ft. of free air per minute, and the fluid raised, 6.25 cu. ft. per minute; or 24 volumes of air to one of fluid raised. The theoretical horsepower necessary to raise the fluid at this rate is 9.24. The steam engine driving the compressor delivered 36.7 i.hp. Hence the over-all efficiency was 25.18 per cent.

In the Kern River field of California, certain wells producing large amounts of water with the oil were operated by air lifts for several years. It was found impossible to remove the volume of water entering the wells with plunger pumps, and air lifts were introduced as a last resort, continued production being contingent upon the ability of the pumping device to keep pace with the influx of water. Expensive compressor plants were installed and an efficient system of piping the wells and of operating the lifts, worked out. In a representative series of tests described by E. A. Rix, the fluid pumped was a mixture of water with 20 per cent of oil. The average lift was 470 ft., with an average submergence of 40 per cent and an average length of discharge pipe of 800 ft. With a working air pressure of 152 lb. per square inch, using the equivalent of 140 cu. ft. of free air per minute, 93 gal. of fluid were pumped per minute. The ratio of free air to fluid pumped is seen to be about 11 to 1. The eduction tubes were 3 in. in diameter and the air pipes, 1¼ in. It was found that continued operation of the air lifts in the Kern River field apparently caused further influx of water, probably as a result of general subsidence of fluid levels due to more rapid extraction. Eventually means were devised for excluding most of the water, so that the smaller volume of fluid, now mostly oil, could be more economically handled by plunger pumps. The air-lift process of pumping was therefore abandoned in this field, and is not generally regarded with favor by California operators, except for special purposes.

J. A. Tennant gives operating data on an air-lift well in the Humble field, Texas.[7] This well was 2,593 ft. deep, but was pumped against a lift of only 669 ft., with a running submergence of 621 ft., or 47.7 per cent submergence. The operating pressure was 330 lb. per square inch. The starting submergence was 900 ft. and the starting pressure required was 468 lb. The eduction pipe was 6 in. in diameter, and the air line 3 in. The lift delivered 85 gal. of fluid per minute.

Selection of the Method of Pumping

Average operating conditions in the American oil fields dictate the use of the plunger pump for lifting the oil. It may be applied to wells of any depth, and adapts itself readily to a wide range of conditions. It is therefore only in unusual circumstances that other methods need be considered. The bailing method is primitive and inefficient, and is employed only where production of large quantities of unconsolidated sand with the oil may prevent satisfactory operation of a plunger pump. The intermittent action of the swab is also mechanically inefficient. Though the suction effect developed by its use stimulates the production of oil, the labor and power costs are high if it is operated continuously, and its chief field of usefulness would appear to be found in occasionally lifting the oil from wells which do not produce enough to warrant continuous operation of a power plant. The air lift is of service in pumping wells which are capable of producing more fluid than a plunger pump can handle, and is of particular value in operating wells which produce

large quantities of sand. It is definitely limited, however, to relatively shallow wells of high fluid level.

Since the plunger pump is the usual lifting device employed, the only questions that are ordinarily presented are those concerned with selection of the type of power, and with the manner of applying it. Of prime movers, there are four to be considered: the steam engine, the gas engine, the oil engine and the electric motor. A discussion of the relative advantages of the several types of power for pumping service will be found in Chap. XIV. The power may be applied either by pumping "on the beam," or in multiple with the aid of jacks or by pumping "units" or steam heads. The latter two are but rarely employed, and the interest usually centers on a choice between the first two methods. Multiple pumping is desirable only on fully developed acreage, when the wells are relatively shallow or moderately deep, when they are not too widely scattered and produce steadily with only infrequent necessity for well repairs. For deep-well service, for erratic producers requiring frequent repair work and for scattered production characteristic of the development period of an oil-producing property, operation of the wells by beam pumping with individual engines or motors is the only available method.

Pumping Costs

The cost of pumping will be the all-important consideration in making a choice between one method or another, and in determining the most economical kind of power to use. While every oil field has peculiarities that require careful consideration in making comparisons of costs, the following data are offered as indicative of typical lifting costs in some of the oil fields of the western[4] and southwestern United States:

I. Plunger Pumps Operated on the Beam. (*a*) *Using Steam Power.*

1. A property in the Kern River field of California has 20 wells which vary in depth from 1,050 to 1,175 ft. The gravity of the oil is 15°Bé. Natural gas is the fuel used, and water is supplied from wells on the property. The figures were assembled during the year 1922.[4]

Cost of Operating 20 Wells for 1 Mo.

Fuel (average of 7 mo.)	$1,210.00
Water	100.00
Three pumpers at $5.50 per day	495.00
Three oilers at $5.50 per day	495.00
Interest on investment, 6 per cent	30.00
Depreciation, 8 per cent	40.00
Lost production	180.00
Expense of car	60.00
Total cost, 20 wells, 1 mo	$2,610.00
Total per well per month	130 50
Total per well per day	4.35

2. A group of 12 wells varying from 600 to 1,200 ft. deep in the Midway field, California, are pumped with individual steam engines. The gravity of the oil is 13°Bé. Average costs during 1913 were as follows:

Labor	$ 409.50
Fuel oil*	523.20
Water*	697.00
Repairs to boilers and engines	88.44
Lubricants, waste and packing	97.42
Total	$1,815.56
Average daily cost per well	5.09

* *Note:* Boiler water was purchased at 5 cts. per barrel, and fuel oil was valued at 50 cts. per barrel.

3. A group of wells averaging 2,745 ft. in depth in the Coalinga field, California, produce 17°Bé. oil and are operated by individual steam engines at each well. The cost per well during 1913 was as follows:

Labor (attendance)	$104.88
Fuel oil	105 47
Labor (scaling boilers)	15.62
Repairs, material	9.57
Engine repairs, labor	5.56
Lubricants	7.73
Boiler flues	4.00
Water	17.17
Total per well per month	$270.00
Total per well per day	9.00

It will be noted that records (2) and (3) above comprise bare operating costs and do not contain any general or distributed expense.

4. The following record indicates the cost of equipping wells in the Coalinga field with individual steam engines in 1913:

One 23-hp. engine, complete	$296.69
One 40-hp. boiler	473.00
Boiler connections	116.15
Engine house, blocks, lumber, labor	66.80
Total cost per well	$952.64

(*b*) *Using Gas Engine Power.*

1. A group of wells in the Midway-Sunset field range from 1,500 to 2,500 ft. in depth and are operated by individual gas engines. The wells produce from 15 to 200 bbl. of 16°Bé. oil per day, and are operated by individual gas engines. The initial cost of equipment, including cost of installation, and the cost of operation and maintenance during 1922 were as follows:[4]

Initial cost, including installation:

One 30-hp. gas engine with pipe and fittings	$2,025.00
One 50-bbl. circulating tank	170.00
Cement	45.00
Labor, including foundations, hauling and setting engine	155.00
Miscellaneous, 5 per cent	119.75
Total	$2,514.75

Operation and maintenance (cost per well per month):

Labor, including pumpers and repair men	$13.70
Fuel	23.10
Interest on capital investment, 6 per cent	10.12
Depreciation, 8 per cent	13.33
Production lost from shut-downs	16.00
Expense of car	6.25
Cost per well per month	$82.50
Cost per well per day	2.75

Note: In many cases, gas used in developing power is produced on the property. If there is no market or other use for the gas, its value may be regarded as the bare cost of trapping and transmission.

2. A group of 8 wells averaging 2,745 ft. in depth, in the Coalinga field, California, produce 17°Bé. oil, and are operated by individual gas engines at each well. The gas used for power is produced on the property and is not given any value in the following costs, which represent 1913 conditions.

Labor, 2 pumpers at $3.50 per day	$210.00
Lubricants, $7.50 per well per month	60.00
One-quarter time of 2 repair men at $8.50 per day	66.00
Repairs and renewals	120.00
Total, 8 wells, per month	$456.00
Total cost per well per day	1.90

(c) *Using Electric Motors.*

1. A large oil company operating in the California fields reports the following comparative costs for wells pumped on the beam by gas engines and electric motors:[4]

	Cost per well per day	
	Gas engines	Electric motors
Labor, including pumpers, engine repair men and electricians	$ 893	$ .589
Fuel or electric power	......	.800
Repairs	.076	.024
Lubricating oil, waste, packing and miscellaneous	.186	.038
Interest (7 per cent) and depreciation (10 per cent on engines and 4 per cent on motors)	.509	.263
Production lost from shut-downs on 50-bbl. well, at 40 cts. per bbl	.586	.014
Totals	$2.250	$1.728
Saving by electricity over gas, per well per day	$ .52	
Average saving per well per year	189.80	

2. Comparative cost of pumping 107 wells, average depth 800 ft., 13.5°Bé. oil, California fields:

	Cost per well per day	
	Steam	Electricity
Maintenance, pipe lines, wells, pumps, rigs, boilers, motors, transformers and power lines	$ .95	$ .70
Labor, including pumpers, boiler men, electricians and well gang	.65	.45
Fuel oil at 35 cts. per barrel	1.17	.12
Water, waste and lubricating oil	.52	.13
Electric power, assuming 1 ct. per kilowatt-hour	.....	.57
Totals	$3.29	$1.97
Saving per well per day, by electricity over steam	$ 1.32	
Average saving per well per year	481.80	

II. Plunger Pumps Operated in Multiple by Jack Plants.

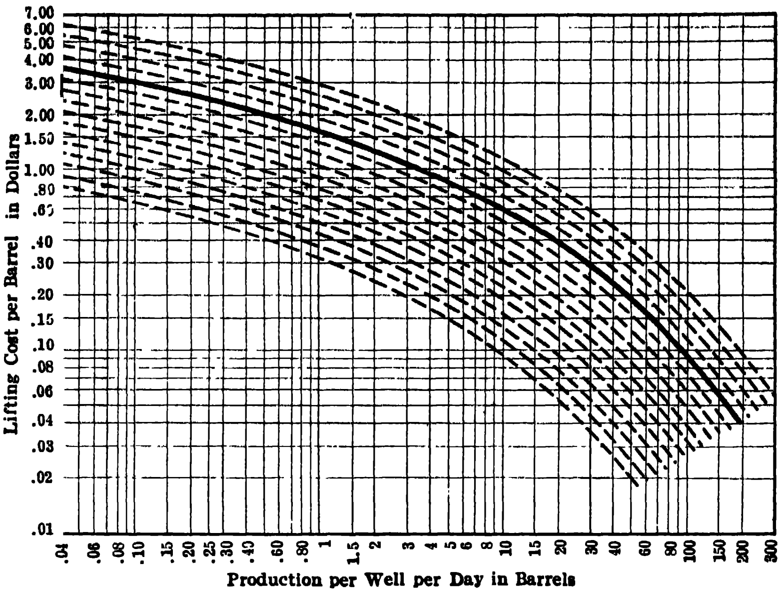
1. The following figures show the power and labor cost of operating 222 wells in the Kern River field, California, by means of 14 central power stations:[4]

	Total Cost for 222 Wells for 1 Mo.
Power,* average for first 6 mo. of 1922	$1,725.00
Labor, 5 oilers at $5.50 per day	825.00
Two automobiles	140.00
Total	$2,690.00
Cost per well per day	0.404

* Electric motors are used for driving powers.

Average Cost of Lifting Oil for 4,497 Wells in Various American Fields, 1921.*—Cost data gathered by the U. S. Bureau of Mines in 1921 from 57 groups of properties in various American fields with a total of 4,497 wells of all types, show a variation in lifting cost of from 4 cts. to $4.86 per barrel of production, or from $2.93 to $467 per well per month. The full-line curve of Fig. 231 shows the average cost per barrel for wells of varying output. The area covered by the dotted curves includes all values gathered in the course of this investigation. The parallel dotted curves are useful in predicting future cost of production if established cost figures do not conform with the average curve. For example, a well now producing 40 bbl. per day at a cost of 20 cts. per barrel, will on declining to a production of 0.8 of a barrel per day produce at a cost of about $1.50 per barrel, assuming that the various cost factors do not change in the interim.

* "Lifting costs at Oil Well Properties," by H. C. George, U. S. Bureau of Mines Reports of Investigations, Serial No. 2530, 1923.



(*After H. C. George in U. S. B. Mines Repts. of Investigations No* 2530).

FIG. 231.—Graph for estimating cost of producing oil.

Note: The solid-line curve shows the average lifting cost for 4,497 wells of all types in widely scattered fields of the U. S.

Average Cost of Producing Petroleum in California, 1914 to 1919.—The U. S Federal Trade Commission, as the result of a survey completed in 1921,* estimated the average cost of producing petroleum in California as follows:

Expense item	1914	1915	1916	1917	1918	1919
Lifting expense	\$.068	\$.071	\$ 088	\$.113	\$.134	\$.156
General and administrative expense	.045	.048	.056	.064	.082	.095
Depreciation	.073	.086	.085	.097	.104	.106
Depletion	.071	.079	.084	.080	.076	.075
Royalty	.021	.023	.027	.035	.044	.044
Less credits for gas and casing-head gasoline	004	.005	.007	.010	.012	.013
Total cost	\$.274	\$.302	\$.333	\$.379	\$.428	\$.463

* U. S. Federal Trade Commission, "Report on the Pacific Coast Petroleum Industry," Pt. I, 1921.

The larger companies producing over one million barrels each, annually, operated at lower cost:

Expense item	1914	1916	1918	1919
Lifting expense	$.049	$.068	$.105	$.131
General and administrative expense	.046	.059	.084	.098
Depreciation	.067	.077	.097	.101
Depletion	.069	.080	.072	.070
Royalty	.018	.024	.038	.040
Less credits for gas and casing head gasoline	.004	.008	.015	.015
Total cost	$.245	$ 300	$.381	$.425

The smaller companies producing less than 50,000 bbl. each, annually, produced at a much higher cost:

Expense item	1914	1916	1918	1919
Lifting cost	$.240	$ 275	$.431	$.414
General and administrative expense	.060	.072	.119	.136
Depreciation	.183	.224	.251	.262
Depletion	.193	.311	.295	.307
Royalty	045	078	.098	.094
Less credits for gas and casing head gasoline	.....	....	.003	.001
Total cost	$.721	$ 960	$1.191	$1.212

The volume of production per well is one of the most important factors in determining the unit cost of producing petroleum. As a rule, the lower average cost shown for producers having the largest production, is largely due to their large average production per well.

The effect of volume of production per well on the cost of production is shown in the following table (figures are for the year 1914):

Range of production per well per annum, in bbl	No of companies	Cost per bbl.					
		Lifting expense	General & administrative expense	Depreciation	Depletion	Credits	Total
Over 100,000	3	$.017	$.005	$.006	$.006	.. . .	$ 034
25,000–100,000	7	038	.057	.061	.077	$ 010	.223
10,000– 25,000	35	.086	.038	070	.048	001	.241
5,000– 10,000	25	.145	.045	.090	.108	002	.386
Under 5,000	21	.148	.050	.169	.106	.001	472

The lifting expense and depreciation show a rapid increase as the quantity produced per well is decreased. The general and administrative expense and depletion are very low for the largest production, but do not increase uniformly as the production per well increases. The total cost shows a steady increase as the volume produced per well decreases.

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See also bibliography at the end of Chap. XIII.

Air-lift Pumping

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See also References 1, 7, and 8 above.

CHAPTER XIII

PRODUCTION METHODS: MANAGEMENT OF WELLS TO SECURE MAXIMUM PRODUCTION

Management of wells to secure the maximum recoverable amount of oil and gas is one of the most important problems confronting the petroleum engineer—one which is destined to receive closer attention in future years of declining productivity than it has during the past. Of all mineral products, the percentage of extraction of petroleum is lowest. It seems probable that we fail to recover, by present-day methods, from 25 to 90 per cent of the oil present in our petroleum deposits. Our present inefficient methods of extracting oil must be improved, for the time will come when growing scarcity and advancing price of petroleum will require a reduction of this unrecoverable content.

Drainage of Oil Sands

The extent to which oil may be drained from a sand or porous rock depends upon a variety of factors, some of which are related to the lithological characteristics of the rock, while others depend upon the physical properties of the oil. Important among these factors influencing drainage are the porosity of the reservoir rock, the shape, size and continuity of the rock pores, and the viscosity and density of the oil. The presence of water in association with the oil also has an important influence upon the efficiency of drainage; but most important of all is the pressure exerted upon the stored oil by natural gas, hydrostatic head and superimposed rock masses. Some of these forces tend to drive the oil out of the reservoir rock into the well, while others favor retention of it. Gas pressure, hydrostatic pressure and rock pressure are the active expulsion agents; while the viscosity of the oil, aided by capillarity, adhesion and pore friction, resist movement. The pressure or "head" on the oil must be sufficient to overcome capillary attraction and rock resistance, otherwise the oil is retained by the rock stratum, even though the latter is penetrated by a well. So-called "tight" sands are occasionally encountered, which are apparently saturated with oil, but do not yield it readily.

The openings in rocks in which fluids are storéd, and through which they must be drained, are of several kinds. They have been classified by Lauer* as original openings, including drying cracks, rock pores, shell cavities and dolomitic cavities; and induced openings, including those

* Lauer, A. W., Petrology of petroleum reservoir rocks, *Ec. Geol.*, pp. 435–472, Aug. 1917.

formed by fissuring and rupturing, bedding and joint planes, brecciation, solution cavities and fossil cavities. Apparently a variety of different types of cavities which might influence the movement of oil exist, and the extraction of oil would undoubtedly be influenced by their form and continuity. For sands and sandstones, from which the greater part of the world's petroleum is produced, the cavities of particular significance are pore spaces between grains and bedding planes. In the case of the limestones, which are also important reservoir rocks, joint planes, brecciation, solution cavities and dolomitic cavities are important.

If the oil accumulation has been influenced by favorable geologic structure, the reservoir rock will become almost completely saturated with oil and gas. Occasionally, small quantities of water may be retained by capillarity and become inundated in the oil reservoir, and small globules of gas remain occluded within the rock pores; but the major part of the accumulation will be liquid petroleum. Experimental tests and data from actual well extractions indicate an oil content in excess of 90 per cent of the pore space available for oil storage in most cases.

In addition to the occluded gas, liquid petroleum is capable of dissolving large quantities of the hydrocarbon gases. Just as mineral waters become charged with carbon dioxide gas, so do oils dissolve hydrocarbon gases; and the quantity which the oil is capable of absorbing increases as the pressure increases. Certain California oils are capable of absorbing about 50 per cent of their volume of natural gas (mostly methane) at atmospheric pressures. At higher pressures the absorptive capacity of the oil would be much greater. According to Henry's law of gases, the quantity of a fixed gas that can be held in solution in the oil is directly proportional to the pressure; thus, if 1 cu. ft. of oil holds $\frac{1}{2}$ cu. ft. of gas in solution at 1 atmosphere pressure, it could hold 10 cu. ft. at 20 atmospheres. Doubling the pressure therefore doubles the quantity of dissolved gas, and hence the energy, being the pressure multiplied by the gas volume, is quadrupled.[2] That is, the expulsive energy increases as the square of the pressure, provided there is enough gas present to saturate the oil at the existing pressure. Some of the gases present, such as propane and butane, are condensable at the higher pressures, and thus go into solution as liquids. The effect of this is to increase the expulsive energy at even a greater ratio than the square of the pressure. Methane is the least soluble of the hydrocarbon gases, petroleum having a considerably higher absorptive capacity for ethane, propane and butane. Thus, in addition to large bodies of free gas accumulated in structural traps in contact with the main body of oil, the liquid petroleum itself in a virgin deposit is usually heavily charged with absorbed or dissolved gas which is ready to assume the vapor phase as soon as the pressure is reduced by the deposit being penetrated by a well.

It is agreed by most authorities that this gas pressure is chiefly responsible for such flow of oil into the well as occurs under present-day methods of production. This may be demonstrated from the fact that decrease in oil production follows closely the decline in gas pressure and when the gas pressure is exhausted, flow of oil amost ceases, although much oil may still remain in the sand. Movement of gas through the reservoir rocks toward the wells is more rapid than that of oil, because of smaller frictional resistance, that is, gas flows through the oil to the well outlet. Proof of this is found in the fact that during the early period of productivity, wells commonly produce considerably more gas than the oil simultaneously produced is capable of absorbing. The reservoir rock yields its oil readily until the occluded and absorbed gas is exhausted, when production greatly declines. Since oil production is largely dependent upon gas pressure, the producer should conserve this gas pressure and prevent its dissipation by every possible means.

While gas pressure is recognized as the chief cause of oil movement in the drainage of wells, there can be no doubt that gravity, hydrostatic pressure and rock pressure, forces foreign to the oil but brought to bear directly upon it, are in part responsible for the flow of oil into the well. These forces are enduring, and will ordinarily be responsible for comparatively small yields of oil after the gas pressure has been exhausted.

The hydrostatic head developed within a porous rock is directly proportional to the depth of the superimposed column of fluid. In many fields containing several oil or gas sands, it is found that the closed-in initial pressures increase with depth, and are proportional to the vertical depths below the outcrops of the strata in which the accumulations occur. The direct influence of the pressure of water, with which the rocks are saturated, is here evident.

Rock pressure is supposed to be directly proportional to depth below the surface. Modern conceptions of earth pressure assume that rocks are plastic in varying degrees, and that pressure may be transmitted from the rock structure to liquid confined within the pores. This theory leads to the conclusion that at sufficiently great depths, rocks will flow like viscous fluids, due to the pressure imposed upon them. While it is doubtful if rocks within reach of the drill are greatly influenced in their physical characteristics by earth pressure, the pressure exerted upon the rock fluids may conceivably become important in aiding oil drainage. Increase in productivity of wells with depth may be satisfactorily explained on the assumption that rock pressure and hydrostatic pressure are predominant or indirect factors in oil drainage.

In thick or steeply inclined strata, gravity undoubtedly exerts a considerable influence in aiding drainage of the rock fluids. If it be assumed that a certain inclination of the fluid surface within a sand will cause oil to flow through the restricted rock passages toward the well, it is

apparent that a component of gravity in this direction may be found at a considerable distance from the well (see Fig. 232). It has been demonstrated that the more nearly saturated rocks yield their contained fluids more readily than do those only partially saturated. Since the lower portions of an oil-bearing stratum in the vicinity of a well will be more highly saturated than the upper horizons, the ultimate drainage slopes will be steeper at a distance from the well than in its immediate vicinity. It seems probable that undrained areas will always exist between wells as a result of this "angle of repose" of the rock fluids. If edge water

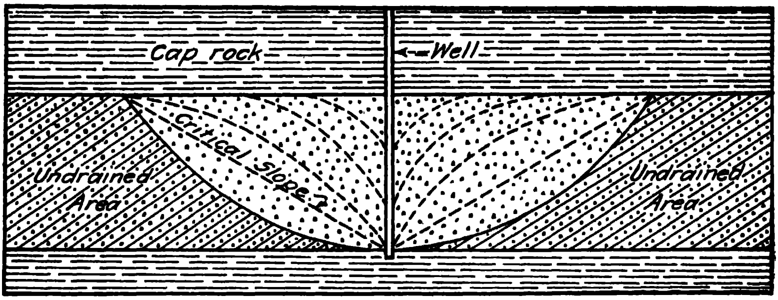


Fig. 232.—Illustrating manner in which gravity influences oil drainage.

The dotted lines show successive positions of the oil surface as the fluid level is gradually depressed by removal of the oil. The solid curve shows the ultimate drainage slope which limits the area drained by the well. Note reversal of curve at critical slope. Water is supposed to be absent. Slopes are greatly exaggerated.

encroaches to fill the voids left by extraction of oil, floating of the remaining oil against the cap rock may accomplish a flattening of the oil "cone," leading to redistribution of the fluid through the upper horizons of the stratum. If water is present in the bottom of an oil sand, too rapid pumping has a tendency to develop water cones in the vicinity of the wells, forming oil surfaces directly the reverse of those illustrated in Fig. 232 for gravity drainage. Theoretically, eventual complete recovery of the oil is possible by these processes providing the wells are not too widely spaced or too rapidly pumped. Under normal operating conditions however, it seems improbable that they are capable of accomplishing anything more than a very slow incomplete extraction of the oil because of the magnitude of the opposing forces and the tendency of edge water to entrap and isolate undrained lenses of oil sand.

The forces opposing drainage of oil from porous rocks are, as suggested above, chiefly capillarity, adhesion and pore friction. The force of capillarity tends to draw the rock fluids into the pore spaces and retain them in spite of powerful expulsive forces. McCoy* estimates that capillarity may exert a pulling force on petroleum of as much as 100,000 lb. per square foot, and in the case of water, three times as much. The well-

* See Reference 14 at end of Chap. I.

known tendency of oils to wet solid surfaces, and adhere to them, is a force of lesser magnitude, but nevertheless one capable of resisting gravity and moderate gas and hydrostatic pressures. Pore friction is a rather uncertain quantity, but in the finer grained rocks it apparently offers an insuperable resistance to fluid movement. This resistance is accentuated by the viscosity of the heavier grades of oils and by accumulation of floating sand in the rock pores. Slichter* gives the data of Table XXXIII which indicates the influence of porosity and pore size on the rate of flow of water through porous rocks. From these data it is apparent that water will flow about 2,500 times faster through a stratum of fine gravel than it will through one of very fine sand, though the percentage porosity may be the same in both materials.

TABLE XXXIII.—RELATIVE VELOCITIES OF WATER MOVING THROUGH SANDS OF DIFFERENT POROSITIES AND GRAIN SIZE UNDER THE SAME TEMPERATURE AND PRESSURE

Kind of sand	Diameter of sand grains in fractions of an inch	Relative velocity of water through sand having a porosity of		
		30 per cent	34 per cent	38 per cent
Very fine	1/254	.003282	.004960	.007170
Fine	2/254	.013150	.019830	.028650
Medium	4/254	.052700	.079400	.114500
Coarse	8/254	.210500	.317500	.458500
Fine gravel	50/254	8.220000	12.400000	17.900000

TABLE XXXIV.—EXPULSION OF OIL FROM A SAND BY COMPRESSED AIR

Total time	Total recovery, per cent	Pressure, lb.
3 min.	....	125
5 min.	50.0	45
10 min.	55.0	
15 min.	57.0	
45 min.	64 0	35
1 hr. 15 min.	66.0	
1 hr. 45 min.	67.5	30
3 hr. 15 min.	69.5	
17 hr. 15 min.	72.0	28

* SLICHTER, C. S., Field measurements of the rate of movement of underground waters, U. S. Geol. Survey, *Water Supply Paper* 140, 1905.

Experiments conducted by J. O. Lewis[10] have demonstrated that saturated porous sands yield their contained fluids much more readily than do those only partly saturated. Compressed air forced through a tube tightly packed with oil-saturated sand gave the yields indicated in Table XXXIV, which shows that 50 per cent of the yield was obtained during the first 5 min., and that prolonged drainage during 17 hr. and 15 min. only resulted in the recovery of an additional 22 per cent. The decrease in resistance to movement of air as saturation decreases is apparently largely responsible for its lower efficiency. In the case of an oil stratum, a similar condition results, the partially drained upper portions of the stratum affording a channel through which gas may flow to the wells without doing useful work in moving oil.

Of the oil retained in the sand after a well has reached economic exhaustion, under the usual methods of production, probably the greater part is held by capillarity and adhesion. The amounts that may be so held are indicated by the data of Table XXXV, which gives the results of prolonged drainage tests with typical oils and sands. The coarse sand consisted of well-rounded grains of uniform size, averaging about 6/254 in.

TABLE XXXV.—QUANTITIES OF OIL RETAINED IN DRAINED SANDS

Oil	Sand	Time drained, days	Oil retained, percentage of capacity of sand
Bradford crude, gravity 41.2°Bé. (0.818)......	Coarse	26	15.0
	Fine	26	21.0
California crude, gravity 25.1°Bé. (0.903).....	Coarse	42	24.0
	Fine	43	42.0
California crude, gravity 14°Bé. (0.972).......	Coarse	73	30.5
	Fine	73	53.0

in diameter, with a porosity of about 37 per cent; while the finer sand was made up of angular grains of irregular size, averaging about 3/254 in. in diameter with a porosity averaging 38.5 per cent. The oil retained within a sand by capillarity and adhesion probably marks the lowest possible limit of recoverable oil, for no system of recovery short of actual distillation or solution could conceivably influence oil held under such forces.

The radius of influence of wells in effecting oil drainage is an important consideration, both in planning the development program for an oil property (see page 80) and in its subsequent operation. The probability of undrained areas existing between wells as a result of the development of drainage slopes toward the wells has already been discussed. This undrained volume of sand of course increases with the distance between

wells. Assuming that forces due to capillarity and adhesion remain fairly constant, as they would in a sand of uniform texture and porosity, the only variable resistance to flow would be that due to pore friction. Just as the pressure necessary to force fluid through a pipe varies directly with its length, so the pressure necessary to overcome rock friction varies with the distance which the fluids traverse. In other words, a greater force is necessary to cause movement of the oil 100 ft. from the well than is necessary to move oil 1 ft. from the well. If this be true, with a uniform pressure throughout the sand, it follows that the areas near the well are more completely drained than are those at a distance; and if the analogy of the pipe line holds, we should expect to find the saturation increasing directly with the distance from the well. But uniform pressures do not prevail throughout the life of a well, and as pointed out above, migration of rock fluids is slow. Hence the oil in the sand immediately surrounding the well will get the benefit of maximum pressure and needs it least; while oil located at some distance from the well will have to move under the much reduced pressure prevailing during the latter part of the period of extraction. Furthermore, there is the probability of gas associated with the distant oil escaping through the unsaturated sands in the vicinity of the well, without doing useful work. If due consideration is given to these factors, the inefficiency of our present methods of oil extraction is not surprising.

Recoverable Content of Petroleum.—Estimates of the percentage extraction to be expected by present methods vary from 10 to 75 per cent. Precise data, of course, are not to be had, most estimates being mere generalities based on judgment and experience. White, in 1904, estimated a 25 per cent recovery for the oil sands of West Virginia. Arnold and Garfias, in 1914, estimated an extraction of from 40 to 60 per cent for the oil sands of California. Dunn suggests 25 to 85 per cent for oil sands in general, and Washburne, 36 to 60 per cent. Actual recoveries obtained in practice indicate that the ultimate recovery in many cases will not exceed 50 per cent. For example, in the data of Table XXXVI, covering estimates of recoverable oil expected from groups of properties in the Coalinga and Midway fields of California,[10] it appears that the maximum recovery by present-day methods will be about 40 per cent. Twenty-five per cent porosity and complete saturation is assumed for the oil sands of these fields.

From the production records of over 6,000 wells on the Indian reservations in Oklahoma, Lewis[10] estimates that the ultimate production per acre will average about 3,400 bbl. which would saturate less than 3 ft. in depth of sand of the porosity prevailing in these fields. It is definitely known, however, that the average thickness of the producing sands is much greater than 3 ft. Hence, a low percentage recovery of the oil content is indicated. Similarly, in the Illinois fields, the production per

acre is estimated at 2,750 bbl., which would saturate about 2 ft. of sand of 17½ per cent porosity; yet the thickness of the "pay streaks" is said to approximate 25 ft. Again, in the Bradford field of Pennsylvania, now practically exhausted, 2,700 bbl. per acre have been obtained—scarcely enough to saturate 3 ft. of sand, although the producing sand is reported to average 45 ft. in thickness.

TABLE XXXVI.—RATIO OF ULTIMATE RECOVERY OF PETROLEUM TO TOTAL OIL CONTENT FOR CERTAIN PROPERTIES IN THE MIDWAY AND COALINGA FIELDS, CALIFORNIA*

	Coalinga field	Midway field
Number of properties	13	18
Average thickness of oil sands, ft	96	90
Average production per acre, bbl	22,012	13,579
Average age of wells, yr	6	4
Average production per acre-foot, bbl	222.5	151
Average recovery, per cent	11.5	7.8
Minimum production per acre-foot, bbl	26.5	51
Minimum recovery, per cent	1.4	2.6
Maximum production per acre-foot, bbl	838	742
Maximum recovery, per cent	43.3	38.2

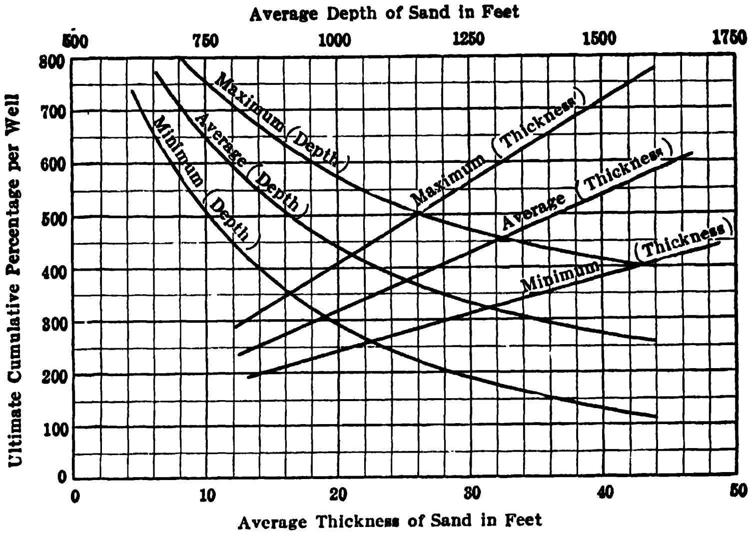
* After R. P. McLaughlin and J. O. Lewis.

Note: The properties included in the above estimates are still operating, but at the time the figures were assembled had yielded at least two-thirds of their ultimate production. Complete saturation and 25 per cent porosity are assumed for the oil sands.

Influence of Thickness and Depth of Oil Sands on Ultimate Production.—Since the storage capacity of a porous rock is a function of its porosity, it follows that the greater the volume of rock available for storage, the greater will be the oil content; hence, the greater the thickness of the oil stratum penetrated by the well, the greater will be the ultimate production. It may also be demonstrated as a corollary that in sands of greater thickness the wells will be of greater initial capacity and will have a slower rate of decline. Deeper sands, probably because of their smaller porosity, are often less productive than shallower sands. These facts are well illustrated by the graphs of Fig. 233, which show for varying depths and thickness of sands the ultimate recoveries, expressed in terms of first year's production, for average wells in the Lawrence County field of Illinois.[5]

Decline Characteristics of Oil and Gas Wells.—The rate of production of oil and gas from wells and the rate at which the production declines are matters of vital importance to the operator. The rate of production

dictates the nature and capacity of the lifting equipment which must be provided, and its manner of operation. It also influences the selection of gathering, storage and other lease equipment. For a given ultimate production, the rate of production also determines the life of the property, or the period over which extraction must be extended. The rate at which production declines is important in determining the relative volumes of oil to be obtained at different periods during the life of the property. The volumetric output during any one period, multiplied



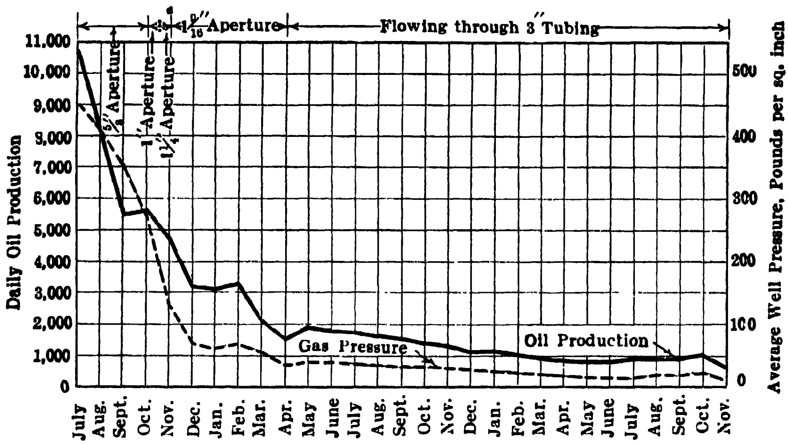
(*After Lewis and Beal*).

FIG. 233.—Graphs showing ultimate recoveries in multiples of first year's production, for sands of varying depth and thickness, Lawrence County Field, Illinois.

by the estimated value per unit during that period, determines the revenue available for operation of the property and for the payment of dividends. Estimates of future annual productions based on such considerations are useful in determining the present value of an oil property and in estimating economic life.

The maximum rate of production is generally reached within a month of the date of completion of the well. The initial rate of production during the first few days or weeks is often erratic, the irregularity being probably caused by the clearing of the wall rocks of mud, fine sands and water, and by the gradual development of drainage channels leading to the well. Some wells require several months or even years before reaching maximum productivity, but it is probable that such wells in most cases have not been properly finished. This initial production peak is due directly to the superior gas pressure characteristic of the early period of production.

The production peak is generally followed by a period of rapid decline, the rate of decline gradually diminishing. This is undoubtedly due to the rapid dissipation of the gas pressure. Oil production reaches a maximum at the beginning of the productive life of the well because the gas pressure has the maximum advantage over rock resistance to flow; but as the opposing forces approach equilibrium, the expulsive energy is reduced and the proportion of oil is correspondingly diminished. It is



(*After C H Beal in U S B Mines Bull.* 177).

FIG. 234.—Oil production and gas pressure decline curves for a flowing well in the Midway Field, California, demonstrating similarity.

evident that there is a basic relationship between the pressure and volume of the gas produced by a well and the quantity of oil produced. In Fig. 234 the gas production and oil production are plotted as separate graphs on the same coordinates to demonstrate the parallelism or similarity in rates of decline that is characteristic of such curves.

As demonstrated above, the expulsive energy which is responsible for oil drainage is chiefly due to occluded and dissolved gas, and in accordance with the gas laws, it increases in effectiveness as the square of the pressure. Evidently, if this assumption relative to the cause of oil drainage is correct, the decline curve of a well, if uninfluenced by artificial factors, should be a logarithmic curve of the general form $y = Cx^n$. The value of n, the exponent in this equation, is an expression of the physical variables—such as viscosity of the oil and texture of the oil sand—which influence the resistance to expulsion. The value of n determines the slope of the curve. The constant, C, is a measure of the productivity of the well. It can be demonstrated mathematically that most production graphs conform rather closely in their decline characteristics with this general formula.[13] In many cases they follow it so closely that an actual equation may be written from which the entire

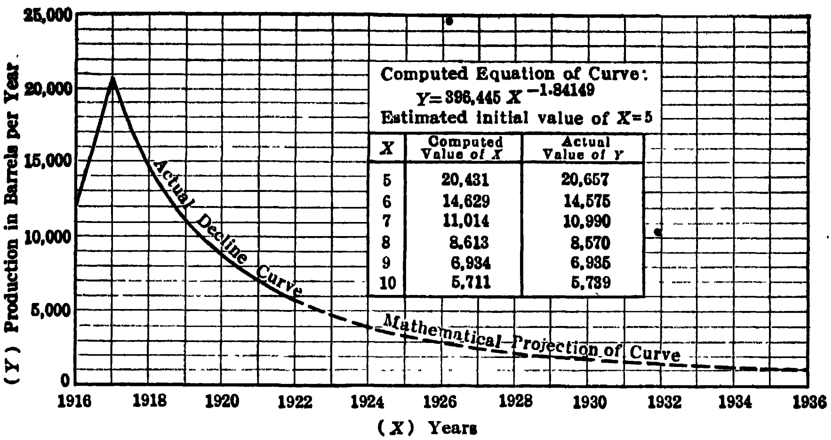


FIG. 235*A*.

Explanation: The equation used is of the form $y = Cx^n$. For any particular curve, values of "C" and "n" must be determined from the data afforded by the established decline curve. Plotted on logarithmic paper, this equation becomes a straight line when the proper initial value of "X" is used. This value of "X" may be determined as illustrated in the logarithmic graph below.

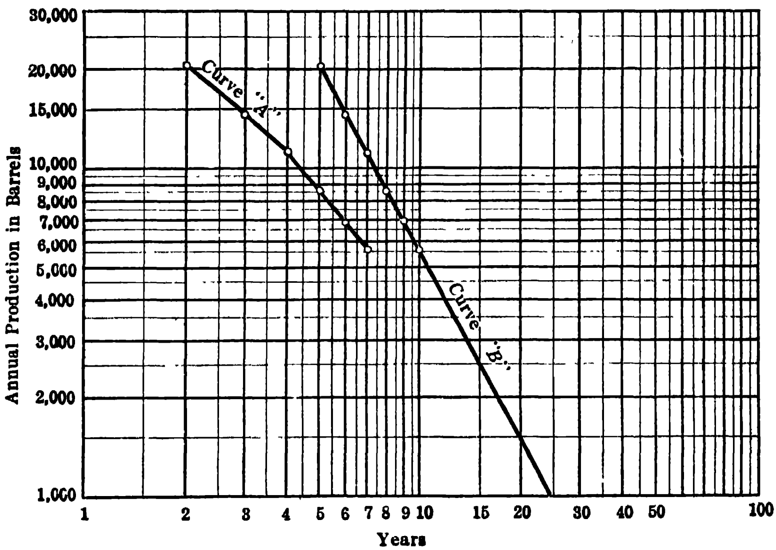


FIG. 235*B*.

Explanation: The logarithmic graph is first constructed by selecting an initial value for "X" at random (curve "*A*"). The curve is then shifted toward its convex side by adding or subtracting a constant to or from each value of "X," until the graph becomes a straight line (curve "*B*").

(*Upper graph after C. S. Larkey in "Mining and Metallurgy," lower graph from U. S. Internal Revenue Bureau's "Manual for the Oil and Gas Industry"*).

FIGS. 235*A* and *B*.—Mathematical characteristics of oil well decline curves.

production graph may be reproduced without reference to the production figures (see Fig. 235*A*). Such a graph should become a straight line when plotted on logarithmic coordinate paper and production graphs are often plotted with respect to logarithmic coordinates in order that extrapolations for the estimate of future productions may be made with greater accuracy than is possible on natural coordinates (see Fig. 235*B*).

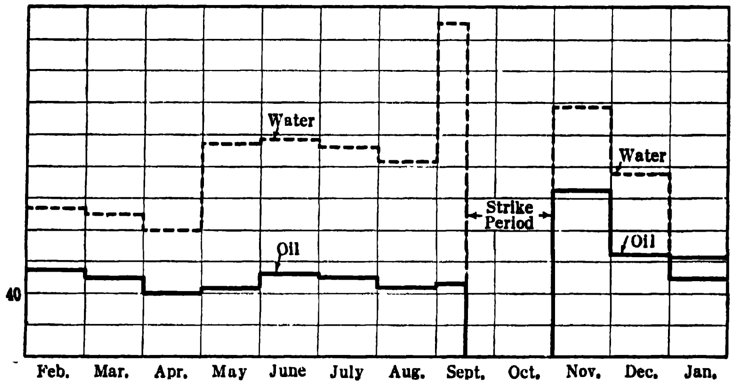
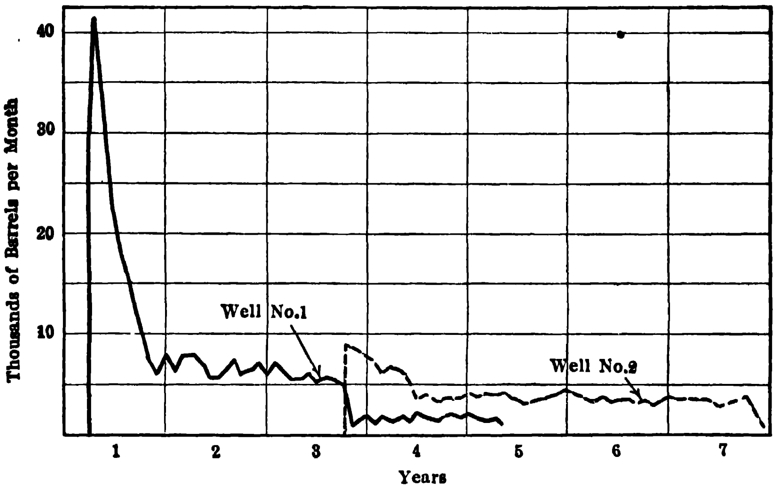


FIG. 236.—Oil and water production graphs for a group of wells in the Coalinga Field, California, showing temporary increase in production following a period of idleness.

Production decline curves often deviate temporarily from the theoretical logarithmic curve which they are supposed to follow, because of various changes in operating conditions. The screens or sand faces may become clogged with sand or wax, which partially prevents flow of oil into the well until it is removed. Pumps may become worn and inefficient and fail to remove the oil as fast as the well is capable of producing it. Wells may be intentionally shut in for a time because of unfavorable market conditions or lack of storage facilities, or on account of labor disturbances. At such times, the natural productivity of the well is artificially influenced and the production graph becomes erratic. It has been shown, however, in certain California fields, that production lost by failure to operate the well at its normal capacity is at least partially regained subsequently, by increased productivity when conditions are again brought back to normal. In the Coalinga field of California, for example, many wells were idle for a period of 4 mo. during 1920 as a result of a strike of oil field workers. A study of production figures indicated that the production lost during this period was regained during the few months immediately following resumption of operations, so that the wells again followed the production curves previously computed for them (see Fig. 236).*

* CHAN, C. Y., Effects of water incursion in the Coalinga field, California, *Thesis* performed under the direction of the author, University of California, 1922.

Uniformity and regularity in the decline rate of course assumes that the wells will not be subjected to conditions which may vitiate the expulsive forces. A new well drilled within the area drained by an older well will at once reduce the productivity of the older well, and the new well will lack the high initial production characteristic of wells drilled in uninfluenced territory. The effect of interference is well illustrated



(*After J. H. G. Wolf*).

FIG. 237.—Production graphs of two interfering wells, showing comparatively small initial production of later drilled well, and sudden decrease in productivity of first well on completion of second.

by the production graphs of Fig. 237. Well No. 2 was drilled only 400 ft. from No. 1 and was completed 30 mo. later. Note the decrease in production of No. 1 on completion of No. 2, and the low initial production and slow initial decline of No. 2 No. 1 is, in effect, brought 24 mo. nearer the end of its economic life by the interference of No. 2, and the latter will produce only a fraction of the oil that would have been obtained had the well been located in uninfluenced territory.

MANAGEMENT OF OIL PROPERTIES TO SECURE MAXIMUM ULTIMATE RECOVERY

It has been shown that gas pressure is the controlling influence in drainage of oil sands, and that when the gas pressure is exhausted, commercial operations by ordinary production methods practically cease. If this is true, obviously every effort should be made by the operator to conserve the gas and permit it to flow from the oil reservoir only in sufficient quantity to secure oil production. Operating methods that permit or encourage the escape of more gas than the minimum amount required to bring the oil into the well will reduce the amount of oil which may ultimately be recovered.

Effect of Holding Back-pressure on Wells.—One method of conserving the gas within the sand and reducing the quantity escaping to that necessary to produce the oil, is found in the practice of maintaining back-pressure on the well. For this purpose, the casing head is made secure against gas leakage and restrictions are provided in the lead lines which build up pressure within the well. Pressure regulating valves, various types of gas traps, flow plugs or a partially "cracked" valve may be used for this purpose. This practice results in temporary reduction in the quantity of the oil produced, due to the decreased rate of flow of gas and oil toward the well during the time necessary to secure equilibrium of pressures within the sand. But after this has been accomplished, the former flow is resumed, and comparatively high back-pressures may be held on the well without reducing the daily oil production. Pressures approaching closely the potential rock pressure of the reservoir may be held within the well without seriously reducing the rate of oil production. The immediate effect of this practice is to reduce the quantity of gas produced with each barrel of oil; and in general, the greater the back-pressure held on the well, the lower the ratio of gas to oil becomes. The back-pressures that are most effective in increasing the efficiency of oil recovery (*i.e.*, ratio of oil to gas) are those which reduce slightly the daily production of the well. The higher the back-pressure held, the greater seems to be the rate of increase in efficiency of production. In this case, the operator must balance the loss in daily oil production against the gain in ultimate recovery resulting from conservation of the gas. That is, by applying back-pressure, oil production will be extended over a longer period, but the ultimate recovery will be greater due to conservation of the gas, and the cost of operation over the longer period must be compared with the value of the increased ultimate recovery, to determine the extent to which this practice may be carried.

In experimental tests on one well in Oklahoma,[12] the back-pressure was increased from 0 to 50 lb. per square inch with a reduction in oil production from 23.2 bbl. per day to 18.5 bbl. The number of cubic feet of gas produced per barrel of oil was decreased from 230 to 88.4. In the case of another well, the gas pressure was increased from 0 to 24 lb. without perceptible loss in the rate of oil production, while the gas production was decreased from 1,496 cu. ft. per barrel of oil to 778.

The volume of gas produced per barrel of oil is a factor that few operators take the trouble to determine, so that figures are not generally obtainable. It is undoubtedly a quantity which will vary widely in different fields, and under different methods of operation. There are probably many cases where development of back-pressure on wells would be inadvisable, particularly where by so doing the oil would be driven to offset wells on a neighboring property; but the method would seem to

offer possibilities of increasing ultimate recoveries and of extending the period of economic operation.

A process known as "stop cocking," which has been applied with favorable results in certain of the Appalachian fields, involves periodical shutting in of a well to increase pressure in the rock reservoir from which the oil flows. Sudden release of the pressure, by opening the stop cock at the casing head, causes an increased flow toward the well, which is said to more than compensate for the loss in production during the time that the well is shut in. Experiments conducted on wells in Oklahoma[12] show that this practice apparently increases the present daily production of oil, but is wasteful of gas, and probably therefore decreases the ultimate production in comparison with recoveries possible through the use of more efficient methods.

The Time Factor in Oil Production.—Production lost or delayed as a result of interruption in pumping service is an important item for consideration in the management of every oil property. Wells are frequently idle for brief periods of time ranging from a few minutes to several days or weeks, as a result of failure of the power, breakage of the pumping equipment or its connections, lack of storage facilities or other causes. Prompt repair work at such times and constant attention to pumping equipment to prevent difficulties of this sort are cardinal principles in the operation of the well-managed oil-producing property. The amount of time so lost will of course vary greatly, depending upon the conditions under which oil must be produced. In some cases where wells must be continually repaired and unconsolidated sands are troublesome, the average well may be "on production" for but little more than 50 per cent of the time. Under favorable conditions, the operating time may approach 100 per cent.

The production record of an oil property is the composite result of the productions of its individual wells, and the operator is chiefly interested in individual well records in determining to what extent they influence or contribute to the property's total. It is usual for a producer to bring his property to a daily production which he considers suitable, by the early and perhaps simultaneous drilling of a sufficient number of wells to secure the desired rate. This results in a rapidly ascending, saw-toothed production curve during the early months, each peak marking the completion of a new well. A brief decline in production following each completion is the result of the rapid decline rate of the "flush" production of the new wells, the troughs becoming shallower with each completion, because as the number of wells increases, the influence of the new wells' production becomes progressively less important in the lease total. Once the desired rate of production is attained, new wells are drilled only at such times as they may be needed to maintain production (see Fig. 31). That is, new wells are completed from time

to time to supplement the declining productivity of the older wells, and the lease total remains fairly constant. Drilling to maintain production assumes that reserve undeveloped acreage is available, for when the property is fully developed, with the maximum number of wells that it will support, the total production will inevitably decline. The decline characteristics of the property production graph during this final period are quite similar to those of an individual well when well advanced on the course of its "settled" production, that is, it exhibits a slow and fairly uniform rate of decline.

The alternative method of early and complete development of the property by the drilling of all of the wells at once, or during a comparatively short period of time, should theoretically produce a greater volume of oil ultimately, but is seldom feasible because of the added cost of the drilling equipment and working capital necessary to drill all of the wells at once. However, such a procedure would drain the property in a shorter period of time, greatly reducing the interest and other standing charges; and would give all of the wells the advantage of maximum gas pressure in accomplishing extraction of the oil. The property production graph in this case becomes quite similar to that of an individual well.

Drilling to Maintain Production.—It is apparent that when the first plan of development outlined above is followed, a more or less constant drilling campaign is in progress throughout the greater part of the productive life of the property. Since the initial productions of later drilled wells will decrease due to decline in the gas pressure, it follows that a constant rate of drilling will fail to maintain production, it being necessary to increase the frequency of well completions as the property approaches full development. If the property is a large one and the production is contributed by a great many different wells, it may become difficult or even impossible to keep pace with the declining production.

A method for estimating the number of wells to be drilled to maintain production on a given property has been proposed by M. E. Lombardi.[11] A period in the property production curve is selected when the production remained fairly constant; the number of wells producing at the beginning and end of the period is determined and the percentage increase is computed. Lombardi's estimates for the percentage annual increase for the Coalinga field, California, was 9.33 per cent; and for the Midway-Sunset field of California, 14.8 per cent. He found that in 1914 it cost $40,000 per year for each 1,000 bbl. of daily production, to maintain the output of the average oil property in the fields mentioned.

Decline in Initial Production of Wells and Its Significance.—As indicated above, the initial production of wells drilled on a given property, or within a limited area, decreases progressively from the first wells drilled. This is occasioned by partial drainage of the sands by the earlier drilled wells, and particularly, by dissipation of the gas pressure. There are

many apparent exceptions to this general rule, in fields where the producing sands are not of uniform texture. Occasionally the early wells are drilled in less productive portions of the field, or perhaps are improperly finished. Later wells located in more favorable positions, and drilled with full knowledge of the position of the productive sand and of the character of strata to be penetrated, develop greater initial productions. However, once a field has reached such a stage of development that its boundaries have been fairly well determined and the productive possibilities of different areas within it are understood, the peak of initial production will have been reached, and thereafter will rapidly decline.

The effect that a well will have in draining the area about it, and its influence on the productivity of subsequently drilled wells in its vicinity, will depend upon the time elapsing between its completion and the finishing of the later drilled wells; also, upon the spacing and the rapidity of movement of the gas and oil through the sand. This latter factor is dependent upon the gas pressure, the coarseness and porosity of the sand, and the viscosity of the oil.

Practice varies in the manner of rating the initial production of new wells. Some operators give the first days' production of a well as its initial rate, while others give the daily rate of production 30 days later. Since the production of the first few days or weeks is often erratic, the latter method seems preferable. Initial productions are always expressed in barrels per day.

Influence of Well Spacing on Ultimate Production.—The subject of well spacing has already been discussed in its relation to the development of oil properties (see page 79). It also has an important bearing on the subject matter of the present chapter. One of the most important factors controlling the rate and ultimate production of oil from a property is the number of wells drilled upon it. Widely spaced wells do not influence each other's productions to the same degree as do closely spaced wells and consequently they decline less rapidly. That is, wide spacing tends toward long life and slow decline, and close spacing results in short life and rapid decline. Since spreading the production over a longer period usually means inefficient use of the gas pressure, close spacing and a rapid rate of production result in maximum ultimate recovery. Considerations of oil price and cost of operation and development enter as important factors in determining economic spacing. These have been adequately discussed in Chap. IV.

The economic number of wells to drill on a given property is determined by balancing the total cost of producing oil—including development charges—against the total amount for which the oil produced can be sold, due allowance being made for deferrence of revenue in computing the present-day values. The cost of extraction does not increase uniformly with the percentage recovery, but in most cases

increases rapidly as the higher percentage recoveries are attained. In most cases, therefore, it is not profitable to secure the maximum quantity of recoverable oil, greater profits being realized on a lower percentage extraction, because the production costs are lower with the less complete recoveries.

With high ultimate production per acre and a higher price for oil, wells can be more closely spaced. The influence of future oil price on well spacing is especially significant. If it be assumed that oil prices during the later years of the productive life of a property are likely to increase greatly, it will often appear that a given property may support double the number of wells which present-day oil prices would justify. The question of whether 64 or 100 wells should be drilled on a section of land would thus be answered by determining whether or not the additional oil recovered and the earlier returns on the investment would compensate for the cost of drilling and operating the additional number of wells; but the most uncertain factor in such a computation is the future selling price of oil.

Table XXXVII illustrates the difference in ultimate production per well and difference in ultimate production per acre due to variation in spacing of wells. These figures were assembled from the average production decline curves of all available records of wells and properties in the two fields mentioned. Each group represents wells producing from approximately the same thickness of the same sands, and under similar conditions except for spacing. Inspection of these figures clearly shows that the ultimate production per well decreases and the ultimate production per acre increases with closer spacing. An interesting relation appears in both the ratio of ultimate production per well and ratio per acre. For example, in the figures for wells of the Nowata district, Oklahoma, wells having an initial production of 6,000 bbl. per acre show, with closer spacing, a decrease in the ratio of ultimate production per well, as follows: 100, 90, 84.5; while wells with an initial production of 4,000 bbl. have almost the same rate of decrease: 100 89 84.5. A corresponding similarity is noted in the column giving ultimate production per acre. In analyzing these figures, Cutler[5] concludes that "the ultimate production for wells of equal size in the same pool, where there is interference, appears to vary directly as the square root of the areas drained by the wells." In other words, the recovery of oil from wells of equal size in the same field, and producing under similar conditions, is proportional to the average distance that the oil moves to reach the well. By applying this principle, production decline curves for wells of different spacing in the same sands may be derived from a given production decline curve for wells of known spacing. Discounting the annual returns to be derived from the property, under different assumed spacing plans, will indicate the most profitable interval.

TABLE XXXVII.—INFLUENCE OF SPACING OF WELLS ON ULTIMATE PRODUCTION

Spacing, acres per well	Initial year's production, bbl.	Ultimate production per well, bbl.	Ratio of ultimate production per well, per cent	Ratio of square root of areas drained, per cent	Ultimate production per acre, bbl.
Nowata District, Rogers and Nowata Counties, Oklahoma					
10.0	6,000	16,900	100.0	100.0	1,690
8.0	6,000	15,200	90.0	89.5	1,900
6.3	6,000	14,300	84.5	79.5	2,386
10.0	4,000	12,200	100.0	100.0	1,220
8 0	4,000	10,900	89 0	89.5	1,366
6.3	4,000	10,300	84.5	79.5	1,717
10.0	2,000	6,900	100.0	100.0	690
8.0	2,000	6,100	88.5	89.5	766
6.3	2,000	5,700	82.5	79.5	950
Bartlesville-Dewey District, Washington County, Oklahoma					
15.0	4,000	14,800	. . .	.....	987
10.0	4,000	14,200	. .	.....	1,420
7.0	4,000	14,000	100 0	100.0	2,000
5.0	4,000	11,300	81.0	84.0	2,260
3.0	4,000	9,750	70 0	65.0	3,250
15.0	2,000	7,770	. . .	...	513
10.0	2,000	7,770	..	.. ..	770
7.0	2,000	7,770	100.0	100.0	1,100
5 0	2,000	6,100	78 5	84.0	1,220
3.0	2,000	5,180	67.0	65.0	1,727
15.0	1,000	3,850	.....	.....	257
10.0	1,000	3,850	.....	.....	385
7.0	1,000	3,850	100.0	100.0	550
5.0	1,000	3,160	82.0	84.0	632
3.0	1,000	2,630	68.0	65.0	876

TABLE XXXVIII.—INFLUENCE OF TIME OF DRILLING ON ULTIMATE PRODUCTION

Tract No.	Area in acres	Year drilling began	Ultimate production per acre, bbl.	Loss per acre in comparison with earlier drilled wells, bbl.
Adair Pool, Nowata County, Oklahoma,				
Within 480 Acres:				
1	160	1909	930	
2	160	1912	678	27% in 3 yr.
In Two Adjoining Tracts:				
3	60	1906	3,240	
4	40	1907	2,946	9% in 1 yr.
Bartlesville-Dewey District, Oklahoma				
Iin Four Adjoining Sections:				
5	40	1905	5,785	
6	190	1906	2,700	53% in 1 yr.
7	200	1907	1,926	29% in 1 yr.
8	80	1908	1,435	25% in 1 yr.
9	30	1910	1,152	20% in 2 yr.
In Four Adjoining Sections:				
10	40	1907	3,521	
11	170	1909	2,560	27% in 2 yr.
In Four Adjoining Sections:				
12	340	1905	3,050	
13	235	1907	2,880	5% in 2 yr.
14	50	1910	2,520	12% in 3 yr.
Nowata District, Rogers and Nowata Counties, Oklahoma, in Two Adjoining Sections				
15	90	1910	4,291	
16	100	1911	2,189	49% in 1 yr.

Time of Drilling and Its Influence on Ultimate Production.—The time at which wells on a given property are drilled, in comparison with the time of surrounding development, has an important bearing on both their initial and ultimate productions. Early wells in the district, receiving the benefit of maximum gas pressure, attain the higher initial productions and ultimate recoveries, while later drilled wells suffer considerable losses in comparison. Cutler[5] gives the data of Table XXXVIII, showing the effect of time of drilling on ultimate recovery.

Mr. Cutler also cites other examples illustrating the loss that results from delay in development: In the Buena Vista Hills region of the Midway field of California, the ultimate recovery for a certain fully developed tract is estimated to be 24 per cent less than that of an adjoining similar tract, due apparently to a delay of 2 yr. in drilling. Again, in the Hewitt field, Carter County, Oklahoma, four wells on 10 acres all had initial productions in excess of 500 bbl. per day. One and one-half months later, a neighbor's offset came in with an initial production of only 220 bbl., while 4 mo. later another offset was completed with an initial production of only 120 bbl. The loss due to 1½ mo. delay in drilling was 53 per cent and with 4 mo. delay reached 73 per cent.

The loss sustained by the operator through delay in development will vary with the extent of surrounding development, the size of the pool, the comparative size of the undrilled area, the extent of delay in drilling and the degree of protection which the operator has secured through the drilling of offset wells.

Economic Life of Wells.—The period over which profitable operation of a well may extend is dependent upon a number of variables, some more or less indeterminate. The life of a well may be approximated by projecting the decline curve to the assumed minimum rate of profitable production. Normal decline in production will progressively reduce the output to smaller and smaller levels, approaching but never, within practical limits, quite reaching zero. It has been shown that decline is rapid during early months, the rate of decrease becoming smaller as the well becomes older. The minimum production rate to which operation of the well may be profitably carried depends upon the cost of operation and the selling price of the oil; and because of the slower decline rate toward the close of the productive life, a relatively small change in the minimum profitable rate of production may greatly prolong the economic life. Thus, a well that declines from 100 bbl. per day to 10 in 3 yr. may decline to 1 bbl. daily in 7 yr. more, and to $\frac{1}{10}$ bbl. per day in an additional 20 yr. A reduction from 1 to $\frac{1}{10}$ bbl. in the assumed minimum profitable rate of extraction may thus treble the life of the well.

In 1914, when California heavy crude was worth 32 cts. per bbl., certain wells producing less than 5 bbl. per well per day were unprofitable, but the same wells in 1921, when oil sold for $1.60, were profitable, though

their productions had fallen to only 2 bbl. per well per day. The grade of oil produced also has an important bearing upon the economic life of a well. While in 1920 the average California well could not be profitably operated for much less than 2 bbl. per well per day, if the same wells had been producing one of the better grades of Pennsylvania crude, which at that time sold for nearly $6 per barrel, operations could have been conducted at a profit for only ½ bbl. per well per day. Shallow wells in the Appalachian region, because of the high value of their product and the low cost of operation, are sometimes operated for but a few gallons of oil daily, perhaps being pumped for only a few hours every week, the small productions not justifying continuous operation.

It is common for appraisers who have particular need for information concerning the economic lives of wells to assume that advancing oil prices will within the anticipated life of present producing wells make profitable a production of 1 bbl. per well per day. On this basis, Lewis and Beal[9] estimate that wells in the Bartlesville field, Oklahoma, have a probable life of from 13 to 15 yr.; those of north Texas and Louisiana (except those of the Ranger field), 15 to 20 yr.; those of southeastern Ohio, 10 to 15 yr.; those of the San Joaquin Valley of California, 20 to 25 yr.

It can be demonstrated from the Law of Equal Expectations, which indicates that wells of the same output have the same future expectations regardless of their ages, that within the same district wells of large initial production will have a longer life than those of smaller initial production.

The law of equal expectations, as advanced by Beal, Lewis, Nolan, Darnell and others, states that within the same pool wells of equal output, regardless of their relative ages, will in future have approximately similar decline curves, equal lives and approximately equivalent ultimate productions. Lewis and Beal[9] have stated the law as follows: "If two wells under similar conditions produce equal amounts during any given year, the amounts they will produce thereafter, on the average, will be approximately equal, regardless of their relative ages." Application of this theory, for example, would indicate that a well completed 5 yr. ago and now producing 100 bbl. of oil per day will have the same future production as a second well in the same locality and producing the same amount, which may be just entering upon its productive life.

While many factors have a bearing on the future production of a well, it appears that the production of the well itself is an expression of the many complex variables involved. Some of these factors, such as the porosity and saturation of the sand, rock pressures and resistance to movement, are indeterminate; but their resultant is measured by the well's decline curve. If the conditions which have influenced past production remain unchanged in future time, the future production will approximately follow the projection of the decline curve. The decline

curve is then, in effect, a graphical solution of the mathematical equation in which all of the physical conditions surrounding the well find expression.

Though the truth of this law of equal expectations is now generally accepted, and while it has been checked by numerous applications in all of the American fields, it must be recognized that many of the variables influencing production of wells are subject to change by man; and it is therefore not always safe to assume that they will remain constant. Failure to keep the wells in good condition may cause a decrease in normal output. Intensive drilling may develop interference between wells, which will influence future production. Influx of water may abruptly terminate the productive life of the well. Application of vacuum or compressed air to the wells, as described in the latter part of the present chapter, will artificially prolong the productivity of wells and increase their ultimate productions.

Maintenance of Wells and Pumping Equipment

This is a matter that must receive close attention if the maximum ultimate production of oil is to be secured. Problems associated with the handling of unconsolidated sands which tend to enter the well, of preventing water incursion, maintaining a free passage for oil through the screens and perforations as well as the wall rocks immediately surrounding the well, are of vital importance, since continued production may depend upon a satisfactory solution. Maintenance and proper operation of the pumping and well equipment is of equal importance, if best results are to be attained.

Fluid Level and Its Influence on the Rate of Production.—Operation of well pumping equipment has been discussed in some detail in Chap. XII, as well as the manner of conducting the usual repair work. It is important that the relation of fluid level to the rate of production and efficiency of extraction be carefully studied for each well. It is obvious that the maximum rate of oil production will be realized with the lowest possible fluid level in the well, for the static pressure of the accumulated oil directly resists the expulsive forces within the sand.

While maintenance of a high fluid level within the well will partially reduce the flow of fluids, it may conceivably exercise a beneficial restraint on the admission of water and gas, without influencing to the same degree the flow of oil, thus preventing water incursion and conserving gas. Also, if sand tends to flow with the oil into the well, a high fluid level is beneficial in preventing its movement. Even though maintenance of a high fluid level reduces to some extent the quantity of oil produced, the advantages gained through better control of gas, sand and water may compensate for loss in production.

Determination of the proper rate of pumping is also dependent upon consideration of the most desirable fluid level, since this has a controlling influence on the well's productivity. That is, the length of stroke and number of strokes per minute of the pump must be adjusted to keep pace with the productivity of the well at the fluid level desired. The stroke and speed of the pump must also be adjusted in conformity with its size and submergence and with due regard to the viscosity of the oil. The space between the valves must be entirely filled with oil on each up stroke of the pump, otherwise the plunger "pounds" on the down stroke—conditions favoring the formation of gas pockets—and the efficiency of pumping rapidly falls off. If the wells do not produce enough oil to operate the pump at full capacity, pumping should be discontinued at intervals to allow it to accumulate. Some wells produce only a few gallons of oil per day, and are pumped for only a few hours once or twice a week.

If the pump is adjusted to operate properly under a certain fluid level, and due to too rapid pumping the fluid level falls, obviously the pump will fail to receive its full quota of fluid at each stroke, thus encouraging admission of air or gas to the working barrel. If the well produces water, it is particularly important to maintain ample submergence and a short, slow stroke of the pump, in order to prevent the formation of emulsions.

Efficiency of the pumping equipment is important, not only from the standpoint of power conservation, but also to insure the removal of the full production of the well. The speed and stroke of the pump are adjusted to keep pace with the productivity of the well, when operating efficiently. If later the valves, plunger or working barrel become worn, or there is a change in fluid level, or leaks develop in the tubing, obviously the capacity of the pump at its original speed and stroke will be decreased. That is, the pump will fail to keep pace with the well's production. Rise in the fluid level which results in this case will compensate to some extent, but this in turn operates to reduce the flow of oil from the sands. Increase in pumping speed will in part offset pump inefficiency, but this in turn leads to increased wear, increased power consumption, the formation of emulsions and other difficulties. The obvious remedy is to properly maintain the pumping equipment to a suitable working efficiency.

Cleaning the well at sufficiently frequent intervals to keep the space within the casing free from accumulated sand is also essential in securing maximum drainage. It is important that sand be not permitted to accumulate within the well to such an extent that it prevents free access of oil from the full thickness of the productive stratum. If an oil sand 50 ft. thick is penetrated by a well and the lower 30 or 40 ft. of it is inundated by accumulated sand within the well, clearly, it cannot maintain its maximum output. Some oil may rise through the accumulated sand from the lower portion of the stratum, but the flow will be slight in

comparison with that obtainable when the well is open to its full depth. Wells are preferably drilled 10 or 20 ft. into the formation underlying the oil stratum, unless there is danger of encountering bottom water, in order to provide a pocket in which sand may accumulate without cutting off production. As often as sand accumulation may warrant, the tubing rods and pump are drawn and the pocket bailed out.

Securing Production from Unconsolidated Sands.—If the sands are fine in texture and unconsolidated, they may flow readily with the oil into the well, and their removal may be the cause of frequent interruption in pumping service. Often a close study of the size and shape of sand grains will suggest a type of screen that will be effective in preventing influx of all but the finest sands, which can be readily handled with the plunger pump. In other cases, application of a moderate back-pressure on the well will hold the sand in place without greatly restricting the flow of oil.

W. H. Kobbe advocates[8] operation of wells producing from unconsolidated sands in such a way as to encourage movement of sand into the well. He argues that even if the material could be successfully held back by screening, it tends to clog the wall rocks surrounding the well until movement of oil is largely prevented by a mass of closely packed, drained oil sand. Considerable percentages of sand may be successfully handled with the plunger pump or with the air lift, and if the sand is encouraged to enter the well, it may be lifted to the surface and more efficiently drained in sumps. Removal of sand from about the wells leaves open spaces and channels which further assist oil drainage. While such a method would probably result in more efficient drainage of the sands immediately surrounding the well than is otherwise possible, the mechanical difficulties encountered in raising and disposing of large volumes of sand with the oil would be troublesome and costly. Furthermore, the development of cavities about the wells leads to shifting of sands with consequent parting, collapsing and bending of the oil strings and liners, and probably also to caving of the cap rock, which may allow water incursion, loss of oil and gas, and extensive earth movements, which may occasion loss of the well. Such difficulties have been common in certain California fields where large volumes of sand have been pumped to the surface with the oil (see Fig. 238).

Prevention of water incursion depends largely upon the effectiveness and permanency of cementing and other exclusion methods undertaken during the drilling of the well. These have been adequately described in Chap. IX. However, water exclusion is a matter of vital importance throughout the productive life of an oil property, as well as during the development period. Indeed, certain phases of the water problem are characteristically associated with the later years of declining productivity (see page 299).

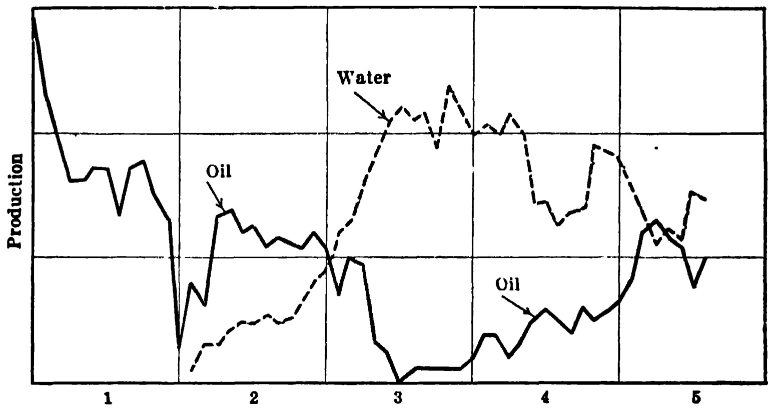
Water incursion or encroachment influences the ultimate recovery of oil in several ways. If it has its source in strata under higher pressure than the oil sand, it may accumulate in the well and oppose flow of oil from the sands. In extreme cases it may even cause flow from the well into the oil sand, thus reversing the direction of flow of fluids and cutting off all production. Such action may be mitigated by pumping the water to the surface as rapidly as it enters the well, but this results in increased cost of operation. Increase in operating cost, in turn, reduces the amount

FIG. 238.—Accumulation of sand brought to the surface by oil flowing from a well.

of recoverable oil, since wells may not be profitably pumped to so small a yield, and the economic life of the well is reduced. Again, oil sands in contact with water do not yield their oil readily. Oil will not flow under low pressures through a water-wet sand. Hence, if the wall rocks become saturated with water, it may become difficult to bring about flow of oil into the well, even though the surrounding rocks contain oil under slight pressure. Loose sand in contact with water does not flow as readily as it does when suspended in clean oil, hence water causes difficulty in the well in facilitating the formation of sand "bridges," sand-packed working barrels, frozen oil strings and other difficulties of a serious nature. Certain types of ground waters in contact with iron and steel tubing and pump parts cause rapid corrosion, necessitating frequent replacement of well equipment. It is claimed by some producers that the presence of water is responsible for slight changes in density and viscosity of the oil produced, to the detriment of its market value. Then too, if water is

present, there is always the possibility of the water becoming emulsified with the oil, with attendant difficulty and expense in dehydrating the mixture after it is pumped to the surface. Obviously, it is to the advantage of the operator to prevent the admission of water to his wells by every possible means.

Many producers find it advantageous to keep a continuous record of water production for each well, showing the amount or percentage of water contained in the well fluid. Such a record is conveniently kept



(*After A. W. Ambrose in U. S. B. Mines Bull.* 195).

FIG. 239.—Illustrating the influence of water production on oil production.

in graphic form (see Fig. 239). If a well produces water, it is usual for the quantity of water pumped per day to remain fairly constant, though the percentage of water in the well fluid gradually increases because of normal decline in oil production. If the quantity of water pumped shows sudden or rapid increase, it is indicative of a condition that requires prompt remedial measures, if such are possible.

Casings gradually corrode, or cement plugs may disintegrate and eventually admit "top" or "bottom" water. Such conditions may be remedied by repair operations. Encroaching edge water will gradually increase the quantity of water pumped from the wells. This is indicative of approaching exhaustion, for which there is no remedy, though in thick oil sands of low dip it will often happen that the water is at first confined to the lower levels of the productive horizon, and progressive plugging of the wells with small quantities of cement will greatly reduce the amount of water to be pumped (see page 276).

A process of "skimming," in which the pump is suspended near the surface of the well fluid, is said to be effective in accomplishing a certain degree of selective segregation of the two fluids within the well. That is, only the oil is removed, leaving the water column in the bottom of the well undisturbed. Some of the wells in Mexico have been operated by

this process after edge water has "broken in," though at greatly reduced output. It is important under these conditions, that wells be not pumped too rapidly else water cones will form about the wells, eventually cutting off all oil production.

A somewhat similar method has also been used in certain areas in the Kern River field of California, which produced large quantities of water, though in this case investigation showed the water to be foreign to the oil sand, and it was necessary to remove the water to prevent the oil sands from becoming entirely inundated. Certain down-dip "key" wells were equipped with air lifts of sufficient capacity to depress the water table over a considerable area. These were operated solely to keep pace with the influx of water, and produced but little oil. As a result of this, other wells more favorably situated in up-dip locations were pumped in the usual manner for oil, and were able to continue production without pumping excessive amounts of water. Some wells were equipped with both a plunger pump and an air lift, the former being operated as a skimming device with low submergence, while the air lift was placed near the bottom of the well to remove the water.

Redrilling Jobs.—Extensive repairs requiring use of the cable drilling tools are occasionally necessary in maintaining wells at their maximum rate of production. Quantities of "heaving" sand may suddenly flow up through the bottom of the casing or through the perforations, burying the pump and filling the lower part of the well. Though the bailer is frequently all that is necessary to remove such material, occasionally the sand packs and the drilling tools must be employed. Collapsed, corroded or parted casings and liners have to be withdrawn and repaired, perhaps requiring heavy pulling due to accumulated wall "friction," and permitting partial caving of the walls, material from which plugs the lower portion of the well. If a water shut-off becomes ineffective and water finds its way into the well below the shoe of the water string, it may be necessary to cement a smaller column of pipe at some lower depth, requiring withdrawal of the lower strings and lining the lower portion of the well with pipe of smaller diameter. Such work may extend over a period of several weeks or months, during which time no production is had from the well. In preparation for it, a certain amount of re-rigging is usually necessary, often involving the installation of a more powerful engine than is used for ordinary pumping service.

After redrilling, wells often resume production with increased vigor, due in part to accumulation of oil and gas about the well during the period of idleness, and also to the removal of spent sand and accumulated sediment from about the well screens and liner. Occasionally redrilling operations result in loss of production, the sands apparently lacking sufficient gas pressure to clear the pores of the wall rocks of loose material with which they become clogged during the process.

Deepening wells involves procedure and equipment quite similar to that made use of in redrilling operations. In this case, however, the object is to penetrate to greater depth than the well had previously attained. Such work may be done many months or years after the original completion of the well, and in some cases represents a considerable increase in development expense. A well drilled into a high-pressure oil sand must frequently be allowed to produce for a time before the gas pressure is sufficiently reduced to permit of proper completion. Perhaps the well originally penetrated only a few feet of the oil sand, when flow of high-pressure oil and gas made it inadvisable to attempt to drill through the full depth of the productive zone. Deepening of wells is frequently necessary also, when production is sought from lower sands the existence of which was, perhaps, unsuspected during the early period of development. If there are several oil sands or zones with intermediate water sands, it will normally be impossible to produce from more than one at a time, and it is customary to exhaust each sand in turn before deepening the wells to produce from progressively lower horizons.

Abandoning Wells.—When wells no longer produce sufficient oil and gas to repay the cost of operation, and it seems probable that they can never become profitable producers at any future time, they should be abandoned. This involves salvaging as much of the casing and well equipment as it may be possible to recover, and the provision of adequate protection to prevent water from entering the oil zone and the waste of oil and gas (see page 298). Withdrawal of the casings usually requires heavy pulling, and some sections of the pipe may be so securely "frozen" to the walls that it is impossible to remove them. In this case, and also in freeing the upper portions of water strings from cement plugs, it is customary to make free use of casing cutters, rippers and explosives. Frequently much of the casing must be left in the well, and often a large part of that withdrawn has been so badly corroded in service, or damaged during the process of removal, that it is of little use for any other purpose.

In order to seal off the productive sands and prevent subsequent water incursion which may threaten the existence of neighboring wells, it is necessary to plug the abandoned well. This is best accomplished by filling it with cement from the bottom to a point above the top of the oil zone. This is done after the removal of the liner or oil string, but before the upper strings are withdrawn.

In certain states it is provided by law that wells be plugged before abandonment as a precaution against flooding of oil sands, and for the protection of other wells in the vicinity. In California, for example, an operator wishing to abandon an unprofitable well must give formal notice of his intention to the State Oil and Gas Supervisor, who prescribes the manner in which the work shall be done. The cost of cement plugging

and other work incidental to the abandonment of a well may involve considerable expense—frequently in excess of $1,000. The value of the salvaged casing will usually compensate for this expense, however. Some operators object to the expenditure of such sums on wells from which there will be no further return, but as a measure of protection to other operators, these regulations are fully justified. Furthermore, when one considers that present-day methods of production fail to recover a large percentage of the oil in the sands, it seems proper that operators should be required to conserve the unrecoverable content for future time in which more efficient methods of extraction may be employed. Since higher oil prices and more efficient methods of extraction are not impossible in the near future, operators should give due consideration to such possibilities before a decision to abandon a well is reached. Some operators carry wells on their records as "idle producers" for many months or even years, before they are definitely abandoned.

Removal of Accumulated Paraffin from Wells.—Wells producing paraffin oils require occasional cleaning to remove solid paraffin wax which accumulates in the pores of the wall rocks, about the screens and perforations or in the tubing and pumping equipment. This accumulation is often due to the chilling effect of expanding gas, but in some cases is simply the result of contact with air or loss of the lighter constituents of the oil by evaporation.

Removal of accumulated paraffin may be accomplished by dissolving it in hot oil or gasoline, or by melting it with heating devices. Solution methods are commonly employed, oil or gasoline being heated in a tank equipped with steam coils, and pumped into the well through a column of tubing. On the lower end of the tubing a tee is placed which deflects the stream of hot oil directly against the screens and perforations. The column of tubing is slowly raised and lowered and turned while the pump pressure is applied, thus bringing the heated oil into contact with all parts of the well equipment. On passing through the screens, the oil finds contact with the wall rocks and removes much of the adhering paraffin. The solvent oil is pumped from the well while still warm, carrying the wax with it in solution.

Melting wax in the wells may be accomplished through the application of steam, heated billets of iron or steel or by electrical heating devices. Live steam is applied through tubing in much the same manner as heated oil. Heated steel billets are lowered in the bailer. Electrical heating devices have often been proposed for this work, but are rarely used because of their costly construction, difficulty of transmitting the current into the well and the absence of electric power in many oil fields. Melting the wax within the pores of the oil sand may seal them more securely unless there is sufficient gas pressure to force the paraffin into the well while it is in the molten condition.

Methods of Increasing the Recovery of Petroleum

The inefficiency of our present methods of extraction have led many producers to interest themselves in devices and methods for increasing the recovery. Methods that have been applied with some measure of success include the application of vacuum to the wells, the application of compressed air, flooding the oil sand with water and the driving of tunnels and shafts into the producing stratum to secure greater drainage surfaces than are possible in wells. It is to such methods that we must look for that increased efficiency in oil production that future generations will demand.

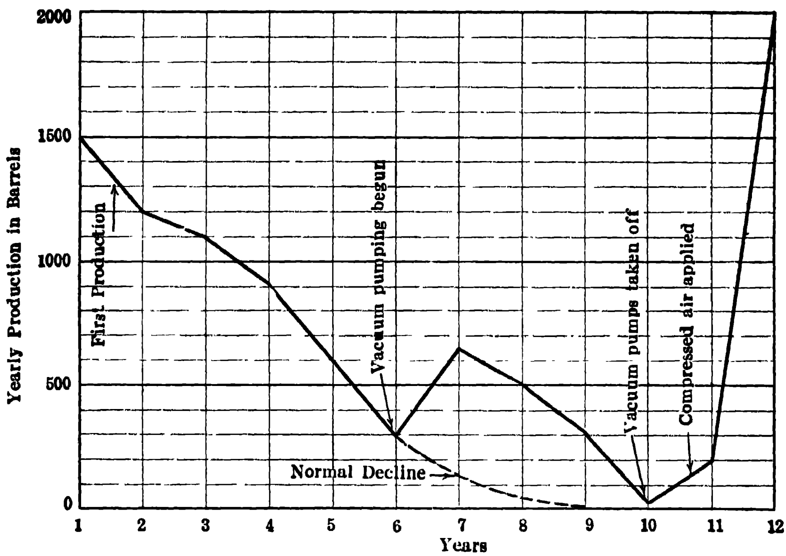
Vacuum Pumping.—It has shown that gas pressure is the principal cause of oil drainage, and that when the gas is exhausted, well productions decline to negligible amounts. That is, differential gas pressure between the sand and the well is the chief cause of flow, and consequently when gas pressure within the sand approaches atmospheric pressure, flow ceases. If by any practical means this differential pressure may be increased, flow will be prolonged and a greater ultimate recovery of oil will be obtained. We may increase the differential pressure either by adding pressure to the oil in the sands, or by subtracting it from the pressure within the well. In other words, the application of 10 lb. of negative pressure or vacuum to the well produces the same result as the addition of 10 lb. to the gas pressure within the sand.

It has become the custom of operators, particularly in certain of the eastern and mid-continental fields of the United States, to apply vacuum to their wells after natural gas pressures have become nearly exhausted, causing immediate increase in daily production to several times the former amount. The production of a well may be so stimulated by this treatment that at the previously established rate of decline it may continue in operation for several years beyond its normal life, provided that the reduced pressure is maintained (see Fig. 240).

The vacuum pumps used in reducing pressure within the wells are usually driven by gas engines, vacuum pumping being productive of considerable quantities of gas. This gas is rich in gasoline-forming vapors, and is available for power purposes after being stripped of its gasoline content in absorption or compression and refrigeration plants. Theoretically, a gas pump should be capable of developing a vacuum or negative pressure of about 1 atmosphere, or 14.7 lb. per square inch at sea level (less at higher elevations). Practically, however, −13 lb. seems to be about the lower limit for well-designed pumps, and when the pumps have to be connected by piping with wells at some distance away, leakage makes it practically impossible to maintain a lower vacuum on the wells than −12 lb. per square inch.

Though it is thoroughly practicable to prolong the life and increase the yield of wells through the application of vacuum, it is an expensive

process, and the increased yield of oil will seldom repay the cost. Considerable expensive plant must be provided and the operating costs are high. Well repairs are frequent because of the tendency of the walls to cave and of floating sand to enter and clog the well openings. The additional production gained through the use of vacuum is short-lived. Often the production of oil is doubled or even trebled when the process is put into use, but this favorable effect seldom lasts for more than 2 or 3 yr., when the production declines to its former level.



(*After J. O. Lewis in U. S. B. Mines Bull.* 148).

FIG. 240.—Production graph of a property in the Chesterhill Field, Ohio, illustrating the effect of vacuum pumping and compressed air in increasing production.

The chief reason for use of the vacuum process is found in the additional quantity of gas secured from the wells with the oil. As explained above, this gas is unusually "wet," and is valuable as a source of casing head gasoline. In fact, the process is used primarily in stimulating gas production for this purpose, and the additional oil produced is generally considered as a by-product. Probably the majority of natural gas gasoline plants in the mid-continental fields and in the fields east of the Mississippi River use gas from vacuum-pumped wells. To a considerable extent, this industry may be said to be dependent upon vacuum pumping for its gas supply, and higher gasoline prices promise to give further stimulus to the vacuum pumping process. It is said to have been particularly profitable in some of the Oklahoma fields during recent years.

Once vacuum is applied to a well, it must be continued, or the well will produce nothing; for when the vacuum is relieved, air flows into the oil sands to equalize the pressures and oil is driven away from the well.

This is one of the practical difficulties of the process, for whenever repairs are necessary in the well, air must be admitted to the sands, and on resumption of operations several days of pumping under suction are necessary before the former flow of oil is regained. Vacuum pumping, if used at all, must usually be applied to all of the wells on a property, for the low-pressure wells will soon secure most of the oil that might otherwise enter wells not so pumped. This means that if one operator in a field places his wells under vacuum, his neighbors must also do so, as a means of protecting their properties against drainage. Competition of this sort leads to premature use of the method, which, as explained above, is costly. Agreements are sometimes reached among all of the operators in a field, to refrain from vacuum pumping until the members of the group as a whole are ready to adopt it.

Application of Pressure to Oil Sands.—As explained above in connection with vacuum pumping, an increase in the differential pressure between the oil stratum and the well may be obtained either by reducing pressure within the well or by increasing the pressure within the oil reservoir. An instance of successful application of the latter principle is found in the use of compressed air to increase the pressure within oil sands in the fields of southeastern Ohio and West Virginia. This process is generally known as the Smith-Dunn process, after the operators who first demonstrated its practical value and secured patents governing its use, though it is also known as the Marietta process because of its first extensive use near the town of Marietta, Ohio. In 1917, it had been applied to about 4,000 wells on more than 90 producing properties. The method is described in detail by J. O. Lewis in *Bulletin* 148 of the U. S. Bureau of Mines.

Various theories have been advanced in explanation of the manner in which the air moves the oil. Some operators believe that air displaces the oil and pushes it bodily through the sands toward the pumping wells. Others assume that air is soluble in oil to some extent, and that the air is at least partially absorbed by the oil at points of high pressure where it is introduced. Pressure is thus created within the fluid, so that it flows, the air being later released when this pressure is reduced. J. O. Lewis[10] suggests from experimental evidence, that the oil is probably worked into a froth by the air, bubbles continually forming and breaking within the pores of the sand and gradually moving the oil toward the pumping wells. Much of the energy stored within the compressed air is wasted through slippage and "by-passing" or channeling of the air through open passages.

In the application of this process, compressed air under a pressure of from 40 to 300 lb. or more per square inch is pumped into the oil sands through centrally located wells, thus forcing the rock fluids to other near-by wells that are pumped for oil in the ordinary manner. There is customarily one air well for from two to six pumping wells, depending upon the character of the producing sands, the spacing of

the wells and the pressures under which the pumping wells are operated. From 5,000 to 20,000 cu. ft. of free air per day is used for each well of a group, including the air wells, or an average of about 10,000 cu. ft. per day. That is, 30,000 cu. ft. of air is forced into each air well daily when one air well serves two pumping wells. This process has resulted in an average daily increase in production to 3½ times the previous rate, and in two instances the daily recovery has been increased ninefold. Mr. Lewis indicates that in certain fields, through the use of this process, the ultimate recovery of oil may be increased by from 20 to 50 per cent (see Fig. 240).

A compressor capacity of from 1 to 3 hp. per well is necessary for the successful operation of this process. The compressor plants are equipped with units ranging from 20 to 100 hp.; two-stage machines direct-connected to gas engines being commonly employed, though single-stage compressors are satisfactory when the pressure necessary is not in excess of 100 lb. per square inch. Compressed air is distributed through mains ranging from 2 to 4 in. in diameter, with 1-in. laterals leading to the air wells. A second piping system serves to gather gas from the pumping wells and transmit it to the compressor plants where it is consumed chiefly as fuel in the gas engines which drive the compressors.

The usual types of pumping equipment are employed, compressed air being used as a source of power. In the fields where the compressed air process has been chiefly used, the wells are shallow, and since the quantity of oil to be pumped is generally small, pumping heads operated by compressed air are found to be well adapted (see page 362). If the wells are deep and must be operated on the beam, power may be supplied by a drilling engine driven by compressed air.

Air is pumped into the air wells, which are cased to the top of the oil sand, a cement plug or wall packer being placed on the casing just above the sand, to prevent leakage of air into the overlying formations. If the pumping wells are operated under back-pressure, they too must be protected by packers placed about the casings just above the oil sand. In rare instances, wells under air pressure have displayed a tendency to flow, and it is possible that further development of the process may permit of the use of a modified form of air lift in which air from the oil sand carries the oil to the surface.

Experience has shown that it is best to use a considerable number of air wells—not less than one air well to four pumping wells, and preferably more. When the air wells are widely scattered, the air must travel long distances through the sands, occasioning considerable friction loss, and requiring high pressures at the source. Furthermore, the equipment and operating cost of an air well are considerably less than for a pumping well. Hence, the fewer the number of pumping wells that can be used without sacrificing production, the less will be the cost per barrel of oil. In order to attain approximate uniformity of pressure within various parts of the producing sands, and to prevent channeling or short-circuiting of the air between air wells and pumping wells, it is preferable to operate the wells under moderate back-pressure. Care is necessary in determining which wells shall be operated as air wells and which as pumping wells. It is common practice to force air into the wells which penetrate relatively porous portions of the oil sand, while the pumping wells are located in "tight" sand areas to prevent waste of air. However, the air wells must be well scattered, and the operator will usually find it to his advantage to apply the air pressure to his interior wells rather than to aid his neighbors by applying pressure to the boundary wells.

The air pressures necessary have little relation to the depths of the wells, but are intimately related to the character of the oil sands and to the viscosity and distribution of the oil. The pressure necessary will also vary with the volume of air used. An exhausted oil sand, or one containing chiefly low-pressure gas, will offer much less resistance than one saturated with oil or water, provided the texture remains uniform. Increase in the number of air wells permits of decrease in air pressure

because the air does not have to travel over such great distances. There is a definite relationship that exists between the pressure and volume of the air and the texture of the sand. In thick, open-textured sands, or sands in which conditions are favorable for by-passing, the air volume will be large; while in tight sands, high pressures and small volumes will be the rule. As drainage of a property progresses, larger and larger volumes of air will be required to expel each additional barrel of oil from the sand, but the pressures may be progressively reduced since the sands are relatively open and there is less resistance to air flow. It appears that the horsepower required per well depends upon the thickness and degree of saturation of the sand, wastage of air and general efficiency of expulsion, rather than upon the texture of the sand.

No detrimental action on the oil by contact with air is noticeable, many operators claiming that the oil is actually of higher Baumé gravity. No increase in deposition of paraffin wax within the wells has been observed, the added pressures apparently aiding in forcing the wax out of the sand openings. Forcing air through the sand generally increases the volume of water produced with the oil, but this increase is proportionate to the increase in oil production, so that the ratio of oil to water remains approximately constant. In some cases the air apparently exercises a selective action on the water, forcing large quantities into the wells with comparatively little oil. Such results, however, are uncommon. Aerated water is found to have a greater corrosive action on the well equipment than ordinary ground water.

The volume of gas produced by the wells is greatly increased by the compressed air process. This is due in part to contamination of the gas with air, and in part to the evaporative effect of the air on the lighter fractions of the oil. At times the air-gas mixture is so lean that it will not burn, but when mixed with additional air, it makes a satisfactory gas engine fuel, though the nitrogen content is apt to be higher than in ordinary carburetted natural gas. This is probably due to absorption of oxygen from the air in the oil sands. Such gas is not as satisfactory for use in gasoline extraction plants as ordinary natural gas, though the absorption process is able to obtain a fair extraction from it. Precautions must be taken, in using the gas, to avoid explosions.

J. O. Lewis[10] estimates the initial cost of equipping for operation with the Smith-Dunn process to be from $50 to $150 per well, or from $30 to $50 per rated horsepower used. These are prewar figures. The cost of operation is somewhat increased in comparison with ordinary pumping methods. Some operators estimate an increase in operating cost of from 25 to 50 per cent, and in extreme cases the cost per well per day is doubled. However, since the oil production is increased by a greater percentage, for a time at least, the cost per barrel of production is reduced.

Up to the present time, the compressed air process has been used chiefly in the fields of the Appalachian region, which are characterized by comparatively shallow wells producing small amounts of light, mobile oil of paraffin base. It has been successful with sands of varying porosity, though it is naturally best adapted to fairly coarse, open-textured sands, the response being slower in tight sands where a higher pressure is required. It seems probable that the method would not be so successful with heavy, viscous oils, nor in lenticular, interbedded or non-continuous sands. In some cases failure has resulted through inability of the operator to control the air within the oil sand, much of it escaping into overlying formations, or by-passing the oil and "blowing through" from the air wells to the pumping wells. Whether or not the method can be applied profitably in a given field can only be answered by a close study of the underground conditions, and in many cases results will be uncertain until an actual trial with air pressure is made.

High-pressure natural gas may be used in precisely the same manner as compressed air, with equally satisfactory results. In fact, natural gas should be superior to compressed air for this purpose since it is more

readily soluble in the oil, definitely improving its quality, and conserving the gasoline content and lighter fractions of the oil. Evaporation of the lighter fractions of petroleum is not so rapid in an atmosphere of natural gas as when in contact with air; and further, the gasoline vapor escaping with the gas from the pumping wells may be readily recovered by passing it through a gasoline extraction plant. It is also probable that oil in contact with natural gas or containing large quantities of it in solution has a somewhat lower surface tension; that is, it is less viscous, and it therefore moves through the sand with less resistance.

If a source of high-pressure gas is available from formations above or below the oil sand, it may be that it could be passed into the oil sand through wells, without the necessity of compressing it. If the gas coming from the wells is passed through a compression and refrigeration plant for the recovery of its gasoline, the dry gas could be piped back to the wells and again injected into the sand, the compressor serving the double purpose of removing the gasoline and providing the moving force which aids in the extraction of oil. Gas may thus be passed in closed circuit between the oil sand and the compressors with little loss, except that used in furnishing power for the compressors, and leakage losses. Compressed gas might also be used to operate the pumping wells, as is frequently done in fields where high-pressure gas is available.

While such a process apparently would have many advantages, it is rare to find natural gas available in sufficient quantity at the late stage in the life of an oil property when methods of increasing declining production begin to interest the operator. It seems probable that returning the gas to the sands might prove beneficial during the earlier years of productivity, though it is doubtful at this stage whether the small gain in production resulting would justify the expense of compression, unless gasoline extraction were also considered as an essential part of the process.

Increasing the Recovery of Oil by Water Displacement or "Flooding." Through the accidental flooding of oil sands by failure to properly exclude water from wells, it was early discovered[10] that oil might be driven through the containing sand by water under pressure. Water introduced into one well until the fluid level is high enough to apply a sufficient hydrostatic head on the oil sand, will cause the water to enter the sand and force its way toward other wells where lower pressures prevail. In doing so, the water must follow the more open channels in which large quantities of oil may be stored; and since oil and water do not readily mix, the oil is driven ahead of the water into the low-pressure wells. The method is sound in theory, but difficult to put into application in practice, due chiefly to impossibility of controlling the water once it is in the oil sand.

Methods of applying the process differ somewhat in detail, depending upon the lithological and stratigraphic conditions. In relatively flat

beds, water may be introduced in scattered wells, driving the oil from several different points toward a group of pumping wells. In steeply inclined strata, water may be simultaneously introduced in a row of wells located well down the dip of the structure, in effect floating the oil up-dip to the wells nearer the crest of the structure. In practice, the location of property lines must receive consideration, and the position of water wells so selected as to avoid driving the oil into neighboring properties.

When water enters an oil sand through a well, it should progressively inundate in an ever-widening circle the area surrounding the well. This assumes that the sands are even in texture and that development on surrounding properties has progressed uniformly. This, however, is seldom true. Actually, the sands will often consist of lenticular areas of tight, close-grained sands, interbedded with relatively porous, coarse sands; or certain stratigraphic components of the oil zone will be of coarser material and relatively more porous than others. It will often be the case that more wells have been drilled on one side of a given property than on others. The result is that the water, following lines of least resistance in moving toward areas of lower pressure, will exercise a selective action, advancing more rapidly in the coarse, porous strata than in fine, close-grained beds; and moving chiefly in the direction of lowest pressure—that is, toward the areas of most intense development in the vicinity.

This movement of water through the oil sands is often very slow—perhaps only a few inches per day—while in other cases it is exceedingly rapid. Slichter's data on flow of water through sands (see page 389), will give some idea of the differences in rate of flow that may be expected. In the Bradford field of Pennsylvania it has been noted that the water may penetrate only 200 or 300 ft. from the well in which it is introduced during the first year, while in the San Joaquin Valley fields of California it is not uncommon for water to flow through the sands from one well to another at the rate of several hundred feet per day.

As the distance from the source increases, the water moves more sluggishly, due in part to increased resistance to flow, and in part to the wider expanse of sands which it must saturate. In the Bradford field, for example, as stated above, the oil advances about 300 ft. during the first year following its introduction, but during later years the advance will be much less, averaging after a few years about 35 ft. per year. Eventually equilibrium is reached and no further movement of the water occurs. In the Bradford field, flow of water practically ceases when a distance of 500 or 600 ft. from the source is reached.

As the water flood advances toward the pumping wells, they customarily develop a pronounced increase in oil production, reaching a maximum just ahead of the water "wave;" but when the water line reaches the pumping wells, production suddenly ceases. Daily pro-

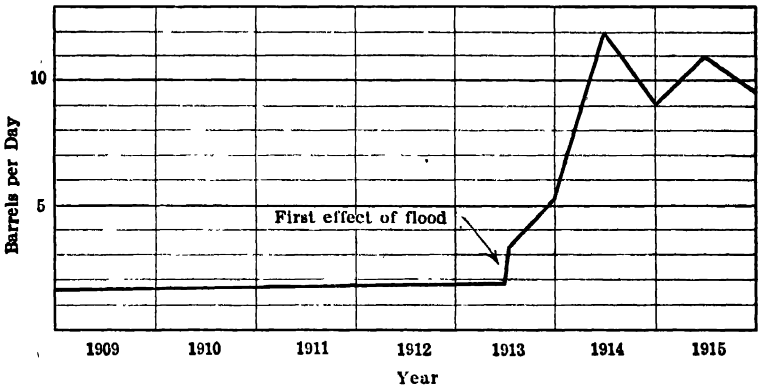
ductions obtained from wells within the area influenced by the advancing water are sometimes increased to 20 or 30 times their previous normal rate and in cases where the rate of encroachment is slow, this enhanced production may continue for many years.

It is apparent that the oil, in retreating before a flood, will move through the channels of least resistance, and in more or less straight lines in the general direction of lower regional pressure. The oil, in other words, does not flow into the pumping wells from all sides as in ordinary production under gas pressure, but enters the well from only one direction. Much oil will therefore be swept by a pumping well, which theoretically only intercepts one element of the wave, and to interpose an effective screen in the path of the wave, it would be necessary to drill several rows of closely spaced wells parallel with its advancing front. In certain of the Appalachian fields, where the method has been chiefly developed, the advance is only a few hundred feet per year, and operators customarily drill wells a sufficient distance in advance of the water line to secure the effect of the stimulated production over as long a period as possible. As one line of wells becomes flooded, these are abandoned or converted into water wells, and others are drilled further in advance of the wave.

The best known instance of the practical application of this method on a large scale is found in the Bradford field of Pennsylvania.[10] Here conditions are said to be especially favorable, and the process has been in successful use for more than 25 years. As indicated above, the movement of water in this field is very slow and uniform, and there is ample time to drill and operate wells ahead of the water wave. Wells are shallow, and may be drilled at a cost of from \$2,000 to \$3,000 per well (1915 figures). Usually, as soon as one well begins to show water, a new well is drilled a short distance ahead, sometimes within 100 ft. It shares in the production obtained from the advancing water for 2 or 3 yr., and then it, too, must be abandoned. The increase in production gained, in comparison with ordinary pumping methods, depends largely upon the distance that the water has migrated from its source. The wells nearest the well through which the water enters are often drowned within a few weeks or months, with but little increase in production, while wells located further away may produce flood oil for years. In many cases wells producing about 1/10 bbl. of oil daily have had their productions increased to from 2 to 5 bbl. daily, an increased rate which may be maintained for 2 or 3 yr. before the well goes to water. Occasionally the production is increased by as much as 10 or 15 bbl. per day. One well reported to have been producing only 1/8 bbl. daily in 1898, just before the practice of flooding was initiated in the locality, was producing 2 bbl. daily in 1916, after producing for 18 yr. under flood conditions. Fig. 241 gives a typical production graph for a property in the Bradford field, and clearly shows the extent to which flood conditions may rejuvenate wells that are approaching the lower limit of profitable production.

The tendency of water to follow the relatively open channels results in much of the oil enclosed within the finer grained portions of the sand being trapped and inundated by the advancing flood. The process is therefore inefficient and particularly objectionable from the standpoint of conservation of oil resources, because the sands are left in such a condition that the oil may not be recovered by any other process. Experiments conducted by Lewis[10] have shown that even under favorable conditions as much as 45 per cent of the original oil content may remain in the sand

after flooding with water. The cooperation and consent of all operators in the locality are necessary before the flooding process may be used, since admission of water to the sands is a matter of general concern. It is directly contrary in principle to the best judgment of many operators who have learned to regard water as the producer's greatest enemy. At present the method is generally regarded as one which may only be applied with success in unusual cases where conditions are especially favorable. It should only be used as a last resort, after the oil obtainable by all other possible methods has been secured; and where a condition of economic exhaustion of the producing sands has been reached.



(*After J. O. Lewis in U. S. B. Mines Bull.* 148).

FIG. 241.—Production graph of a property influenced by flooding, Bradford Field, Pennsylvania.

Mining of Oil Sands.—When the world's petroleum production can no longer be maintained by present methods, it is not improbable that it will be found profitable actually to excavate the oil sands by underground mining, hoist them to the surface and extract their oil content by retorting, by washing or by the use of solvents. Such methods could conceivably obtain a fairly complete recovery of the residual oil left in the sand by present inefficient methods. There are no insurmountable obstacles to prevent the mining of oil sands by such methods as are employed in the extraction of coal. Ventilation would be difficult, and the working conditions more or less unpleasant, but it is thoroughly feasible, as is evidenced by similar operations conducted in sinking shafts and driving drifts through oil sands in the vicinity of Pechelbronn, Alsace.[6] Here galleries have been driven to facilitate drainage of large areas of oil sand, the oil accumulating in underground sumps from which it is pumped to the surface. The drainage of oil from a sand varies with the surface area exposed to the drainage spaces; hence a more complete extraction of the oil content is possible by such methods than is possible through wells of small wall area.

Elliott has shown* that sands pumped from wells by ordinary methods, and thoroughly drained in surface sumps, may yield from 11 to 38 gal. of oil per ton, and that by subjecting the oil to cracking distillation, high yields of gasoline may be obtained. Sands freshly pumped from wells yield as much as 55 gal. of oil per ton. An estimate of the oil available in this way from sumps and surface outcrops in the California fields alone showed that 2,360,000 bbl. might be recovered. In some regions, enormous outcrops of bituminous sands are available at the surface in situations that would permit of cheap open-pit mining. Investigations have been in progress during recent years to devise methods of recovering oil from these materials, and it seems probable that efficient and inexpensive methods will be available for extracting the oil when economic conditions warrant the exploitation of such deposits. Retorting or distillation methods are most promising, though a process of grinding and water-washing is also said to be effective.

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CHAPTER XIV

POWER FOR OIL FIELD PURPOSES

Aside from man and animal power, the principal primary sources of power available for oil field purposes are two in number: first, the energy stored in various types of fuels, and second, the energy developed by flowing or falling water. To these might be added the energy stored within high-pressure natural gas and that developed by moving air or wind. This latter force, however, is too unreliable and difficult of application to be of service in normal oil field operations.

We develop power from the energy stored in fuel, by burning the fuel under boilers to generate steam, with the expansive force of which we operate steam engines and steam turbines. Natural gas produced from the earth under high pressure can be utilized in much the same manner as steam, to actuate a reciprocating piston within an engine cylinder. We may also utilize the energy stored within certain kinds of fuels by burning or exploding them within the cylinders of an internal combustion engine to produce mechanical force through a reciprocating piston. We convert waterpower into electric energy through the instrumentality of the water wheel or the turbine and the dynamo-generator. This energy, transmitted perhaps over great distances, is applied through the use of the electric motor. Our prime movers, then, are the steam engine, the steam turbine, the electric motor and the internal combustion engine. Of the last there are two distinct types: the explosion type, including the gas engine and the gasoline or light distillate engine; and the Diesel or semi-Diesel type of oil engine, which operates on the expansive force developed by the combustion of fuel within the engine cylinder.

Secondary forms of power, or methods of transmitting power, include compressed air and various types of mechanical transmission systems. Air compressed within an air compressor cylinder can be piped over a considerable distance and applied in the same manner as steam or compressed natural gas in the operation of several types of equipment, and for a variety of purposes. The uses of belting and endless rope transmission systems are well known and these methods are widely used for short-distance transmission. For transmission over greater distances, the use of pull lines and "push and pull" systems have been devised and have attained a high degree of perfection in oil well pumping service.

All these different forms and types of power are met with in oil field service and find many interesting and novel applications. Though

electric power is becoming increasingly popular in many phases of the work, the most commonly used prime movers are the various types of engines that are actuated either directly or indirectly by the burning or explosion of natural gas, crude petroleum or various refined and semi-refined products of petroleum. The steam engine and the gas engine are used to develop the greater part of the power used in oil field operations. This results from the abundance and comparative cheapness of petroleum and natural gas, which are ideal fuels for engines of this type.

GENERATION OF STEAM AND ITS APPLICATION IN THE DEVELOPMENT OF POWER

Steam boilers used in oil field service are of all common types, including fire-tube, water-tube, locomotive and Scotch marine boilers. Fire tube boilers of the horizontal-return, tubular type, mounted above brick

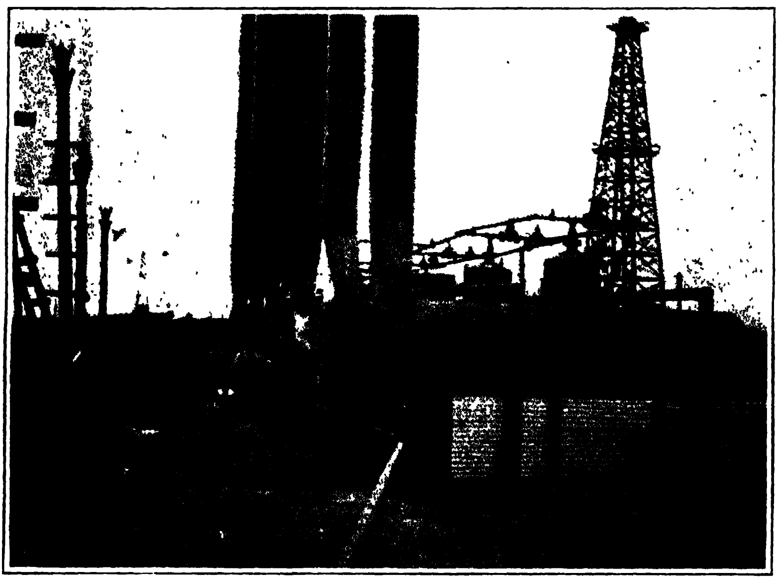


FIG. 242.—A typical field installation of return-tubular boilers.

supports and a brick firebox, are commonly used for field purposes where the service is intermittent, temporary or semi-permanent (see Fig. 242). The locomotive type, in which a water-jacketed metal firebox is riveted directly to the boiler shell, is also favored for temporary service, since this type requires less in the way of masonry supports than any other (see Fig. 243). This type of boiler is occasionally mounted on wheels to facilitate its transportation. For more permanent service, and where larger units are required, as in central power plants, pumping stations

or compressor plants, the more efficient water-tube type of boiler is commonly preferred.

For oil well drilling purposes, it is customary to use boilers of from 30 to 70 rated horsepower, the actual power obtainable from them being normally somewhat greater than the rated horsepower. The steam consumption of a standard cable drilling rig, working at a depth of 2,800 ft. with 8-in. drilling tools, ranges between 55 and 140 boiler horsepower,

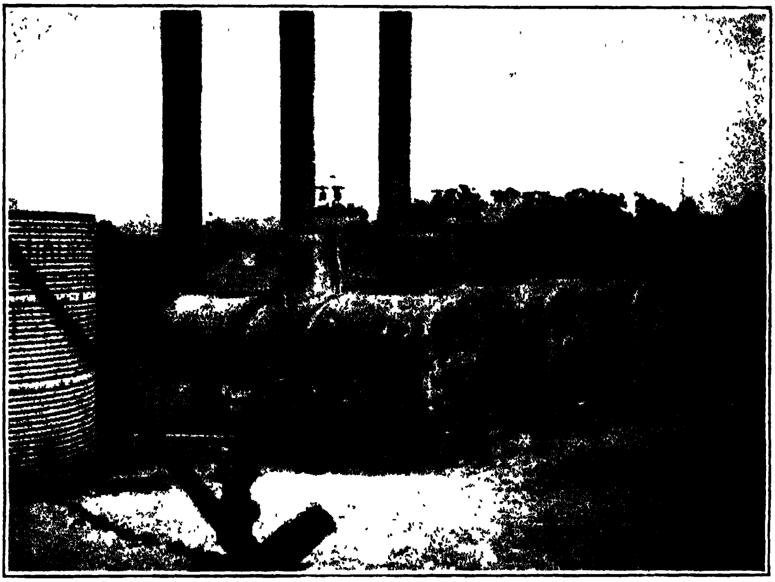


FIG. 243.—A typical field installation of locomotive type boilers.

the latter figure being approached occasionally for short periods of time in drawing out the tools. Drilling on the beam consumes the minimum amount of power and bailing operations require approximately 75 hp. Power requirements for a National portable drilling machine, drilling an 8-in. hole at a depth of 1,800 ft., range between 25 and 64 hp. Rotary equipment requires approximately twice the power used in standard cable drilling. Of this, from 50 to 75 hp. are consumed in the operation of the slush pumps.[1]

It is customary in tubular boilers to allow about 15 sq. ft. of heating surface (2/3 of the surface of the boiler cylinder plus the entire surface of all of the tubes) for each rated horsepower. This amount of heating surface gives an evaporative power of 34½ lb. of water per hour from water at 212°F., to steam at 212°F. The efficiency of this type of boiler, based on the ratio of thermal output to calorific value of fuel used, is about 70 per cent under favorable conditions. Greater efficiency at full load is to be had from the larger units, but a battery of small boilers possesses

greater flexibility and in some ways is better adapted to the extreme fluctuations in output required in drilling service. However, for short periods of time, a single boiler is able to meet a considerable overload beyond its normal capacity for continuous service. This increased power is delivered at the expense of stored heat within the superheated boiler water and surplus steam within the boiler. Such an overload results in rapid loss of pressure.

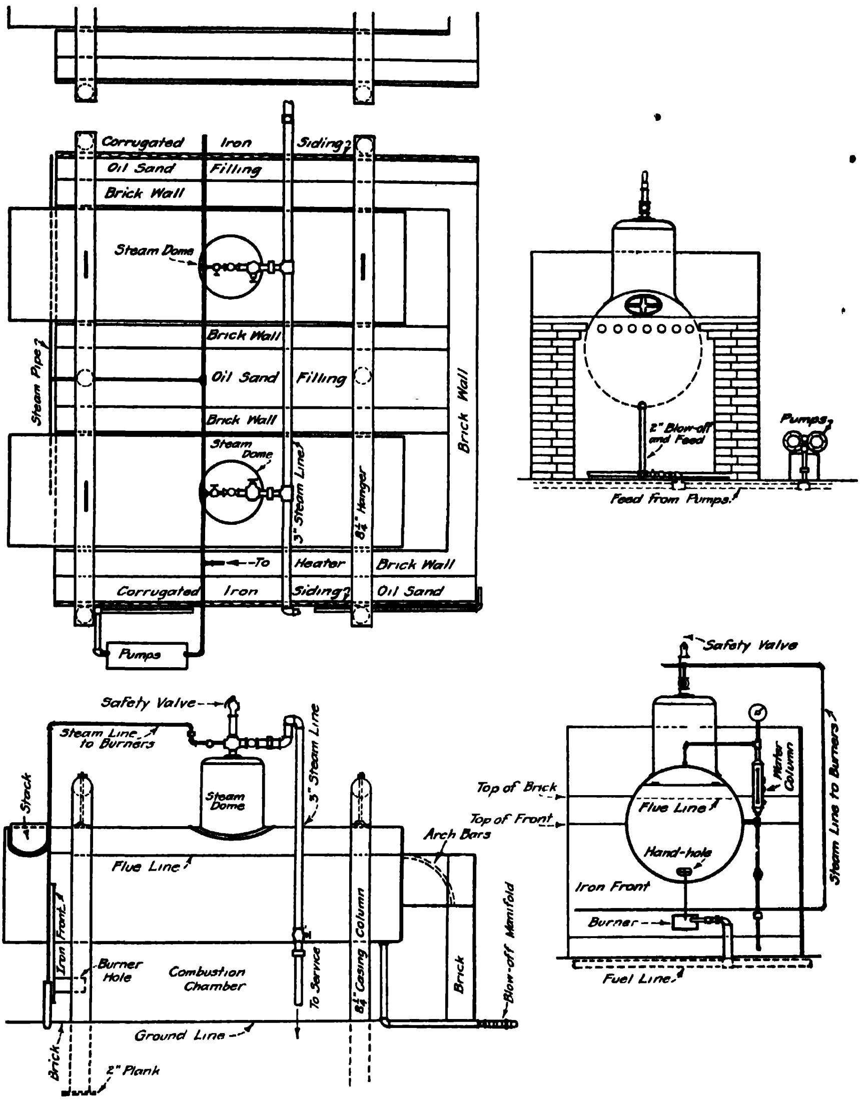
Boilers for drilling purposes are often erected in the open, without housing or protection from the weather, and are usually arranged in groups of two or more near the well for which they are to furnish power. If several wells are drilling at the same time, it is usually economical to serve all the wells of the group from one battery of boilers. Such field installations are often hastily erected and poorly protected against heat losses. The additional cost of providing suitable settings, insulating material and various accessories, giving increased efficiency, is soon repaid by improvement in operating performance. Fig. 244 shows in plan and elevation the details of a brick boiler setting, together with the necessary piping and fittings.

For oil well pumping service, a more permanent installation is provided, and consequently more attention is given to details which tend toward greater efficiency. The horizontal-return tubular (fire-tube) type of boiler described above is also widely used in pumping service, the operator usually making the best of what boiler equipment he has on hand after his wells are drilled. In many cases, however, the steam necessary for pumping all the wells on a property is generated in central power plants, from which steam is transmitted by pipe lines to all parts of the property. In this case, larger boilers are used, of more efficient type, and typical central power plant operating conditions apply. A considerable saving in expense may be realized by this practice in comparison with the cost of operating a number of small scattered plants. However, care must be taken to prevent unnecessary heat and pressure losses in the transmission lines, or the savings realized will be wiped out. With a carefully designed and insulated system of steam transmission mains, one centrally located boiler plant may serve all of the wells on a property a mile square.

In boiler plants designed for some special purpose the requirements of which are definitely known in advance, and where the loads are fairly uniform—as in pipe line pumping stations or gas compressor plants—water-tube boilers of the most efficient type are used. The individual boilers range in rate capacity from 100 to upwards of 600 hp., and they are equipped with all the auxiliary devices that characterize the best central power plant practice.

Efficient operation requires that frequent attention be given to the condition of the heating surfaces within the boiler. Scale, forming as a

result of dissolved solids present in the boiler feed water, must be removed. Tubes that have become weakened by scaling, corrosion or local overheating must be replaced. Safety devices must be periodically



(*Re-drawn with additions, from an illustration in Lucey Corporation's Catalog No. 8*).

FIG. 244.—A typical boiler setting for return-tubular type of boilers.

inspected as a precaution against failure and explosion. The need for occasional repairs and inspection, with consequent interruption in service, makes necessary the provision of a surplus boiler capacity beyond

normal requirements, in order that there may be one or more stand-by units ready to take the place of others which must be shut down.

Boiler Fuels

Crude petroleum and natural gas are almost universally used as fuels for steam raising purposes in producing oil and gas fields. In the drilling of wild-cat wells remote from a supply of these fuels, coal or even wood may be burned under the boilers. If both oil and gas are available, the choice as between one or the other will depend upon their relative market values. As oil prices rise, the cost of crude petroleum for boiler purposes becomes prohibitive.

Natural gas is an ideal fuel; and usually, if it is produced in sufficient quantity, it will be used in preference to oil. There is often a moderate supply of low-pressure gas produced in association with oil, that is not of sufficient volume to warrant the provision of compressor plants and pipe lines to carry it to a commercial market. Under such circumstances its use in power development on the producer's property becomes almost obligatory. Residual gas from gasoline extraction plants is often utilized as boiler fuel.

While many operators prefer a pressure of from 5 to 15 lb. per square inch in the gas used for boiler purposes, it has been demonstrated that operations can be satisfactorily and more efficiently conducted on lower pressure gas. Pressures as low as 2 or 3 oz. are suitable for use under boilers through burners of suitable design.

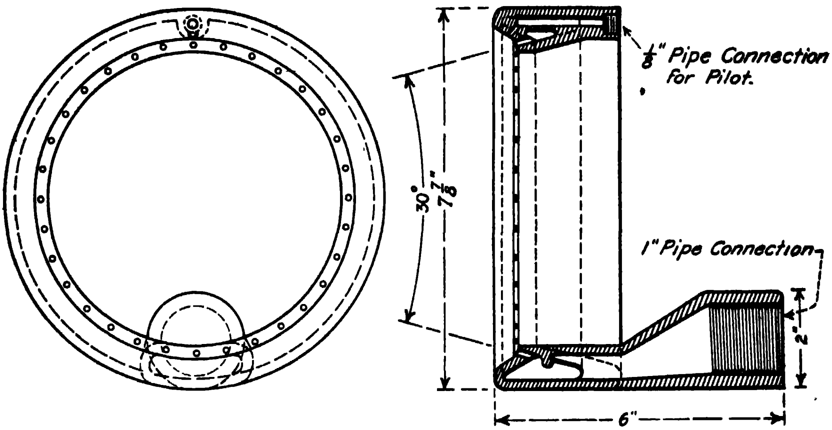
Good results are obtained through the use of multiple burners similar in general form to the ordinary Bunsen burner.[11] These are made of pieces of 1- or 2-in. pipe, 6 or 10 in. in length, with gas jets $\frac{1}{8}$ or $\frac{3}{16}$ in. in diameter. The multiple burners are set under the firebox, with the open ends projecting through a lattice work of protective firebrick. From 30 to 70 of these burners are required to fire a 40-hp. boiler for operating a standard cable rig. Simpler forms of gas burners are ordinarily met with in oil field boilers, which usually consist of some kind of a mixing tube into which gas under pressure is discharged (see Fig. 245). This type of burner is open to the atmosphere outside the firebox, and the suction effect developed by the gas draws in sufficient air to support combustion, the air and gas being intimately mixed within the tube as they are discharged into the firebox. Careful adjustment of the gas pressure and volume to conform with the proportions of the mixing tube is necessary to prevent the gas from channeling through the air without securing the desired mixing effect.

More elaborate gas burners of this same type utilize compressed air or steam to secure the desired jetting effect through the mixing tube. These are useful when the gas is of insufficient pressure to draw in the necessary volume of air. Difficulty is sometimes experienced in the use of steam or compressed air in this way as a result of irregularities in pressure. In some cases a sudden shutting down of the load on the boiler will extinguish the fire by increasing the pressure of the steam jet to such an extent that no gas enters. When the gas itself is used to jet in the air, the amount of air taken in with the gas varies with the amount of gas delivered, the ratio of air to gas thus remaining approximately constant. About 11 or 12 volumes of air for each volume of gas should be admitted to the firebox for complete combustion.

The air which is drawn into the mixing tube by the gas is not ordinarily sufficient for complete combustion, and additional air is drawn into the firebox to make up the deficiency by the stack draft through doors or vents in the front of the firebox. The

gas should burn rapidly since the firebox is often small and the time during which the gas is passing through is short. A large combustion space gives the best results, say about 2 cu. ft. per rated horsepower.

The calorific value of natural gas ranges between 850 and 1,100 B.t.u. per cubic foot, and averages about 950. If 65 per cent of this heat is utilized by the boiler in the



(*Manufactured by Apex Engineering Co., Los Angeles, Cal.*)
FIG. 245.—Apex gas burner, 8-inch size.

generation of steam, 1 cu. ft. of gas is capable of evaporating about ⅔ lb. of water at 212°F. Since 1 hp. represents the evaporation of 34½ lb. of water per hour, at 212°F. a 40-hp. boiler should theoretically require about 2,000 cu. ft. of gas per hour, or 48,000 cu. ft. per day (assuming that it delivers only its rated horsepower). The average consumption of gas per day under a 40-hp. oil field boiler, operating a standard cable drilling rig, probably averages in excess of 100,000 cu. ft. per day, but investigation has shown that this may be reduced by at least 50 per cent through the use of low-pressure gas, suitable burners, and by careful attention to air supply, boiler insulation, leaks, draft, etc. The Hope Natural Gas Company has reduced the average gas consumption under field boilers to only 37,000 cu. ft. per day by a close study of boiler losses.[11]

The quality of the gas used for boiler purposes is of minor importance. The percentage of other gases than hydrocarbons present as impurity (such as nitrogen and carbon dioxide) reduces the calorific value somewhat, but the impurities are not ordinarily present in sufficient amount to make the gas unsuitable for boiler purposes. Even the poorest of natural gases has a higher calorific value than much of the manufactured gas sold in our larger cities for industrial purposes. Gases containing unusual amounts of sulphur may have a corrosive effect on brass fittings, and may cause rapid deterioration in the boiler tubes, plates and stack.

Crude Petroleum and Fuel Oil as Boiler Fuels.—When gas is not available in sufficient quantity for boiler fuel, or is more valuable for other purposes, either crude petroleum or fuel oil will be used. As a rule, crude petroleum is used because it is more readily obtainable, though it is generally profitable, except in the case of the very heavy oils, to install a small topping plant, separating the gasoline from the residuum which is used for fuel purposes. The petroleum industry suffers a great economic loss through the use of high-grade crude as fuel under boilers. Whether or not topping the crude before use under boilers is profitable depends upon the gravity of

the oil, the percentage of motor distillate produced from it and the prevailing field price of crude. The cost of redistributing fuel oil from the topping plant must be considered as an additional factor. In some American fields, between 5 and 10 per cent of the gross production of crude petroleum is used as fuel by the producer.

While not as convenient in their application as natural gas, crude petroleum and fuel oil are excellent fuels and have many advantages that are now generally understood and appreciated. The calorific value varies between 17,500 and 20,000 B.t.u. per pound. Assuming that 65 per cent of the heat liberated by combustion is utilized in the generation of steam, 1 lb. of fuel oil will evaporate about 16 lb. of water from and

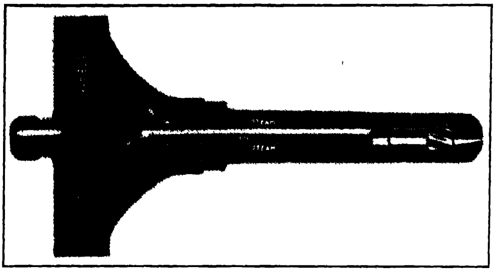


FIG. 246.—"Gem" steam atomizer for burning fuel oil.

at 212°F. This is equivalent to slightly more than 2 lb. of fuel oil per boiler horsepower-hour. If the feed water must also be heated from normal atmospheric temperatures to 212°, as is usually the case, the amount of fuel used will necessarily increase, in some cases to nearly 3 lb. of oil per horsepower-hour. The average 40-hp. boiler employed in drilling service consumes between 7 and 10 bbl. of fuel oil per day.

In order to burn fuel oil satisfactorily, it must be injected into the firebox in the form of a fine spray, with sufficient air to support combustion. For spraying the oil, special types of burners have been developed which may be classified into three main groups: (1) steam atomizers, (2) compressed air atomizers and (3) mechanical atomizers. For field boilers, steam atomization is commonly preferred (see Fig. 246), but in central power plants mechanical and compressed air atomizers have been successfully adapted. The design of the burner nozzle is such that the oil is sprayed into the firebox in the form of a cone, sometimes flattened on top so that it will not strike directly against the boiler plates. The burner should be so constructed that it can easily be removed and cleaned, and so that it has a considerable range of adjustment as regards steam or air and oil supply.

The air necessary to support combustion is drawn into the firebox through openings in the boiler front around the burners. If the oil is properly sprayed, if sufficient air is admitted and the temperature within the firebox is not too low, the oil should burn with a clean, bright flame, and be completely consumed without soot or smoke. About 200 cu. ft. of air at 60°F. are necessary for the complete combustion of 1 lb. of fuel oil.

There is comparatively little difference in the heating value of different fuel oils and crudes. In determining the suitability of an oil for steam raising purposes, we are more concerned with the impurities present, particularly water and suspended solids. Crude oils are often used in the fields before dehydration, with the result that considerable volumes of water may be sprayed into the firebox along with the oil. This not only cools the furnace gases, but results in irregular operation of the burners. Particles of sand or clay carried by the oil may clog the restricted passages of the

burners. As in the case of natural gas, unusually high percentages of sulphur may prove detrimental to the boiler tubes and plates.

In order to force the oil through the restricted passages of the burner, pressure must be applied to it, either through a gravity feed system, or by means of fuel oil pumps. The latter method is safer and is generally preferred. Fuel oil is often too viscous to flow readily, and to reduce its viscosity, it must usually be heated. Small steam-operated fuel oil pumps of the duplex reciprocating type are generally provided, and the fuel is heated in a small cylindrical tank fitted with steam coils. Two pumps and one heater are often mounted together on the same casting and are known as a fuel oil "set." In ordinary fuel oil practice, the pump pressures applied range from 100 to 200 lb. per square inch; and the temperature at which the oil enters the burner should be such that the viscosity of the oil is reduced to about 8 times that of water. The temperature necessary to accomplish this will depend upon the characteristics of the oil used. Ordinarily, temperatures ranging between 150 and 250°F. will be sufficient.

Methods of Increasing the Efficiency of Oil Field Boilers.—The efficiency of oil field boilers is often low as a result of faulty design or insufficient attention to operating details and heat losses.[11] The economical firing of a boiler depends upon proper combustion of the fuel and efficient application of the heat evolved. The firebox of the average boiler does not provide sufficient space for the complete combustion of the fuel necessary during the overloads to which the boiler is often subjected. The fuel should burn completely in the firebox and not in the boiler tubes. The air control and draft are important features which do not generally receive the attention they deserve. The boiler flues and tubes should be cleaned frequently and thoroughly. Firebox doors are often removed and lost. Air may be admitted to the firebox in such a manner that it does not mix properly with the fuel. Frequently too much air is admitted, the excess beyond that necessary for complete combustion diluting and reducing the temperature of the furnace gases. Few oil field boilers are equipped with dampers. A damper in the stack provides an additional means of controlling combustion, and if properly manipulated, results in improvement in boiler efficiency and saving of fuel. The cost of preheating the boiler feed water, and of treating it to remove scale-forming dissolved salts, is amply repaid by increased efficiency.

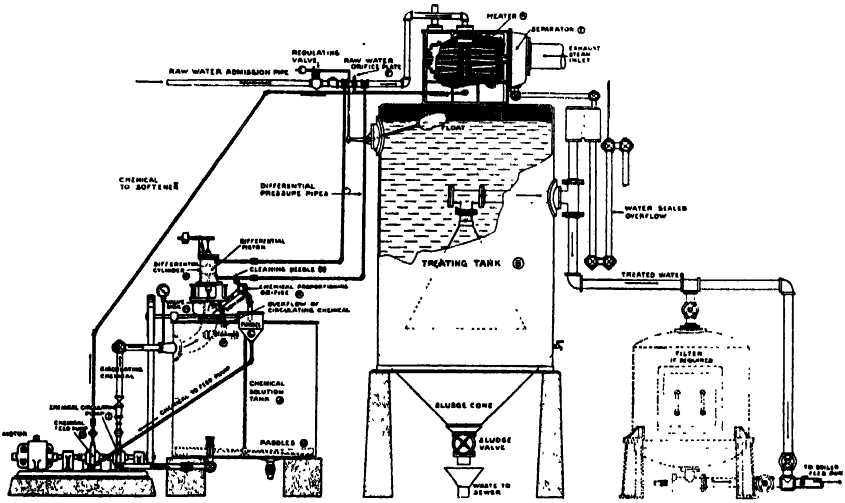
In oil field practice, little attention is given to radiation losses. Field boilers are often erected in the open, without protection of any sort from the weather. The temporary character of many field installations perhaps justifies this practice, though much heat is lost through radiation in cold, windy climates as a result of lack of proper housing. Up-to-date operators are insulating all exposed parts of their boilers with various non-conducting materials, such as magnesia, silocel and asbestos plasters. Loose brick piled over and about the boiler is also effective, the cracks being filled with clay or sand. Oil sand is an excellent insulating material, and is often used on field boiler installations. Corrugated iron sheets, supported by a rough frame of timber or old casing, serve to keep the oil sand in position.

Boiler Feed Water.—Unless the water used for steam generation is free from dissolved salts, acids, organic matter, oxygen and sediment, these impurities will accumulate in the boiler as incrustating solids, or will result in corrosion, foaming or "priming." Active scale-forming salts commonly present in water are the bicarbonates of lime and magnesia, sulphate of lime, and the oxides of iron, aluminum and silicon. These salts form an adherent scale on the boiler surfaces, greatly reducing the ability of the metal to absorb heat, and causing local overheating of the boiler plates and tubes. Magnesium chloride and sulphate, acids, dissolved carbonic acid, oxygen, organic matter and grease cause corrosion. Corrosion may take the form of rusting or pitting of the boiler surfaces, actual solution of the boiler metal, or of "grooving," a mechanical action which is greatly intensified by acidity. Galvanic action between the dissolved salts and the boiler metal is occasionally the cause of rapid corrosion. The presence of certain organic materials or finely divided solids in suspension will cause foaming. An excessive amount of sodium carbonate, sodium sulphate or sodium chloride in the boiler water will cause priming or irregular discharge of steam from the boiler. Any of these occurrences may result in a considerable reduction in boiler efficiency through heat losses, restriction of evaporative capacity, weakening of boiler metals and interruption in service because of the frequent necessity for "blowing down," or cleaning of the boiler surfaces. Such difficulties are common in oil field practice because of the prevailing high salinity of ground waters in such regions.

In order to correct these difficulties, it is customary to subject boiler water containing impurities to chemical and physical treatment.[3] There are four general methods employed: (1) the use of various chemicals to precipitate the dissolved salts before the water enters the boiler; (2) the use of chemical reagents (boiler compounds) within the boiler, with the purpose of forming new compounds with the dissolved salts that do not form adherent scale; (3) the mere application of heat to the feed water before it enters the boiler, resulting in a reduction of its power to hold certain salts in solution, and (4) combinations of (1) and (3).

Chemical treatment outside of the boiler usually involves the addition of soda or lime or both. Slaked lime in solution as lime water will precipitate calcium and magnesium bicarbonates. Sodium carbonate and hydrate of soda (caustic soda), used either alone or together, will precipitate the sulphates of sodium and magnesium, if carbonic acid or bicarbonates are not present. The combined lime and soda process, which is by far the most generally used of the chemical processes, precipitates the sulphates of lime and magnesia, even in the presence of an excess of carbonic acid or bicarbonates. Barium carbonate and hydrate are also effective reagents as substitutes for lime in the removal of calcium sulphate and carbonate, and though more expensive, are sometimes preferable if for any reason it is desirable to avoid the addition of lime. Silicate and oxalate of soda are occasionally used for the same purpose. Alum is used in coagulating organic material.

Treatment of water within the boiler by the use of so-called "boiler compounds" has for its primary purpose the prevention of scale formation, though it is also used to some extent for the removal of scale already formed on the boiler surfaces. These compounds almost invariably contain sodium carbonate and certain tannic compounds, and in some instances a gelatinous substance which is supposed to encircle particles of scale and prevent them from adhering to the boiler surfaces. Their action is ordinarily to precipitate calcium sulphate in the water by means of the carbonate of soda, forming a non-adherent form of calcium carbonate which may be readily blown off when the boiler is drained. The tannic compounds are used with



(*Manufactured by H. S. B. W.-Cochrane Corp., Philadelphia, Pa.*

FIG. 247.—Sorge-Cochrane water softening apparatus.

the idea of introducing organic matter into any scale which may have already formed, with the purpose of loosening it. Scaling of the boiler surfaces by this method is apt to cause rapid deterioration, and is looked upon with disfavor by most authorities. When proper care is taken to select a boiler compound that is suited to the water in use, however, and when used primarily as a scale preventive rather than a scale remover, the results secured are fairly satisfactory; though chemically controlled treatment outside of the boiler is always preferable.

Heat treatment of boiler water without the addition of any chemicals is successful in removing calcium sulphate and the carbonates of lime and magnesium. Calcium and magnesium carbonates are insoluble above 212°F. Calcium sulphate is partially soluble at the boiling point of water, but becomes increasingly less soluble as the temperature rises, until at normal boiler temperatures it is practically insoluble.

Some of the most successful methods of boiler water treatment subject the water to both heat and chemical treatment before it enters the boiler. The heat treatment involves but little additional expense since efficient boiler operation demands that the boiler water be preheated in any case. The apparatus used in one well-known process combining chemical and heat treatment is illustrated in Fig. 247. By means of an orifice and differential valve mechanism, this apparatus adjusts the supply of chemical to conform with the volume of water entering the treater. Its operation is almost automatic, and the results are more uniform and dependable than when ordinary hand mixing of the chemicals is practiced.

It is customary to make frequent quantitative tests of both the raw and treated water, to determine the amount of chemical to use, and the efficiency of treatment. Volumetric methods are used, titrating with a standardized solution of sulphuric acid, using methyl orange as indicator to determine alkalinity, and with phenolphthalein to determine "causticity" or excess of lime. A standard soap solution is also used as a measure of the degree of "hardness."

Water treated by the soda-lime process will ordinarily contain from 3 to 5 gr. of scale-forming matter per gallon. In general, only waters containing over 6 gr. per gallon will deposit scale.

The cost of boiler water treatment will, of course, vary within wide limits, depending upon the character of the water, the local cost of the necessary chemicals and the method of treatment. The capital cost of a water purification plant ranges between $500 and $750 per 1,000 gal. treated per hour, the smaller plants costing more per unit of capacity than the larger.

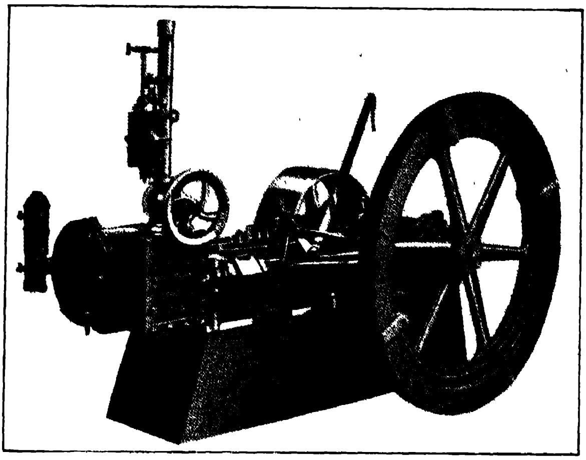


Fig. 248.—"Ajax" steam drilling engine.

Steam engines for use in oil field operations vary widely in size and design, depending upon the purposes for which they are used. For cable drilling, and in many cases also, for pumping service, the simple, single-cylinder, reversible, slide-valve type of engine, built in units ranging from 15 to 50 hp., is widely used. Simplicity, flexibility and accessibility for repairs are matters of prime importance in the selection of an engine to meet the variable requirements imposed.

The type of engine generally used in cable drilling practice, and also in pumping service, has a cylinder 12 in. in diameter, a piston stroke of 12 in., and when operated under a steam pressure of 100 lb. per square inch, develops about 30 hp. For lighter service in the drilling of shallow wells or in providing power for pumping wells, an 11- by 12-in. (25-hp.) or even a 9- by 12-in. engine (15-hp.) of the same type may be used. Larger sizes up to 14 by 14 in. (50 hp.) are used in rotary drilling. Fig. 248 illustrates a well-known oil country engine of this type.

The steam supply to the engine is regulated by a throttle controlled from the headache post by a telegraph cord and handwheel. A simple reversing link on the eccentrics, controlled by a lever and rod from the headache post, enables the driller to control the direction of rotation of the driving pulley. A heavy flywheel, to which additional weight in the form of extra balance rims may be clamped, serves to equalize the loads on the engine. Special lubricating devices, boiler feed water pumps and heaters are often a part of the drilling engine equipment.

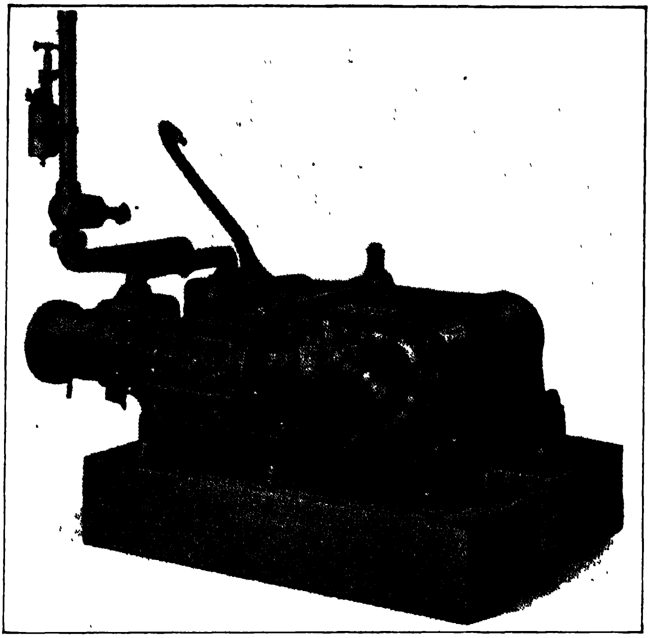


FIG. 249.—"Ideal" twin-cylinder steam drilling engine.

For rotary drilling, a twin-cylinder engine has been developed which has met with considerable favor among drillers and engineers (see Fig. 249). The cranks are in this case set on quarters so that there are no dead centers, and the flywheel characteristic of the one-cylinder engine may be eliminated. With this type of engine a more uniform pull is delivered and driving strains on the drilling equipment are materially reduced. For rotary drilling, 10- by 10-in. cylinders are used, the two cylinders delivering about 50 hp. with 100 lb. steam pressure.

Under the best conditions possible, that is, with dry steam under a pressure of from 100 to 125 lb., and with full load, such engines will consume from 30 to 40 lb. of steam per horsepower-hour. With only one-quarter full load, these figures may be nearly doubled, and with poor general mechanical conditions characteristic of many oil field

installations, the steam consumption may rise to upwards of 100 lb. per horsepower-hour. When such an engine is used for pumping, steam consumption will range toward the higher figures. In many cases, wells operated by individual steam engines require the burning of 3 or 4 bbl. of oil per well per day to generate sufficient steam for pumping purposes. For drilling, as much as 8 or 10 bbl. of oil per rig may be necessary.

In large stationary units, such as are required in compressor plants or oil pumping stations, the best types of compound, condensing steam engines, with mechanically controlled valves and superheated steam, are commonly used. Greater efficiency is, of course, attained by such engines than is possible with the engines used in field service.

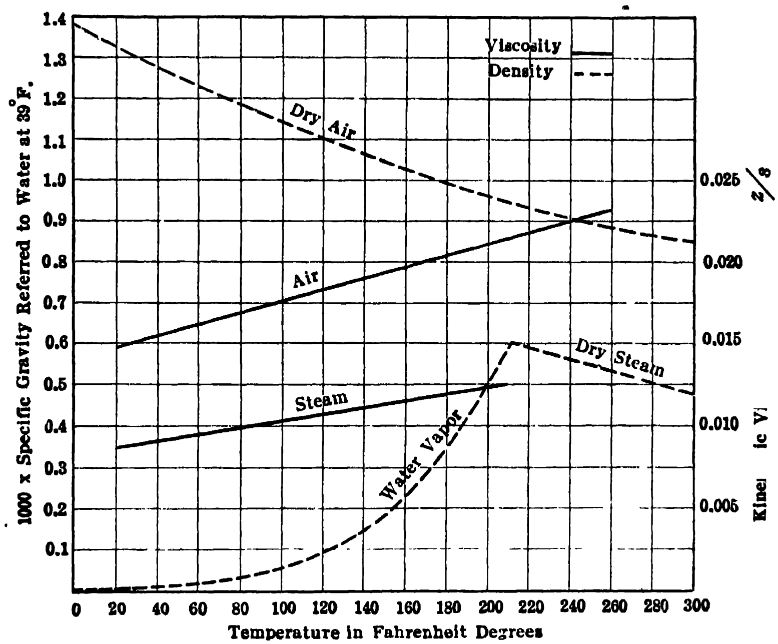
Steam Transmission.—The economy and effectiveness of steam power is vitally dependent upon the design and character of the steam piping. Unless the pipes are protected against heat radiation, large power losses will result through condensation and consequent loss of pressure. Leakage of steam at pipe joints and fittings may also be responsible for large losses. In long steam lines, the pipes must be of adequate cross-section to accommodate the volume of steam to be transmitted, without serious frictional resistance. In the case of branched mains, the sizes of pipe used must be proportioned to the volume of steam each branch is to carry, or to the number of engines served.

For short steam lines, say from 50 to 100 ft. long, the cross-sectional area of the steam main should be about one-fifteenth of the area of the piston to be driven.[3] This insures nearly full boiler pressure at the engine. For long lines, as in distributing steam from a central power plant to a number of wells, the pipe sizes must be increased, otherwise there will be serious loss of pressure at distant points. The size of the pipe must be porportioned to the maximum demand that is liable to arise, and will naturally be in excess of average demand. Radiation losses and frictional losses are opposing factors in the design of steam lines. As the size of the pipe increases, radiation losses increase; as the size decreases, friction losses increase. In either case, loss in pressure results. In modern practice, steam velocities ranging from 6,000 to 15,000 ft. per minute through the transmission mains are not uncommon.

The flow of steam through pipes is governed by the same hydraulic laws applying to all other fluids. The Fanning formula, discussed elsewhere in this volume (pages 551 to 560), can be applied to determine unknown factors in steam flow if the necessary variables are known. In connection with such computations, the density of steam at different temperatures and its kinematic viscosity may be determined from Fig. 250.

Radiation losses in steam piping, with consequent condensation, can, of course, never be entirely avoided, but can be greatly reduced by the application of suitable pipe coverings. Bare pipe will radiate approxi-

mately 3 B.t.u. per hour per square foot of exposed surface, for each Fahrenheit degree difference in temperature between the steam and the external air. This figure may be reduced to from 0.3 to 0.4 B.t.u. for the same conditions, by the application of a 1½-in. insulating covering. Mixtures of asbestos, hair and carbonate of magnesia are the most efficient coverings. For best results, all exposed main steam lines, flanges, valve bodies and fittings should be covered with from 1½ to 2



(*After Wilson, McAdams and Seltzer, in Jour. Ind. & Eng. Chemistry*).

FIG. 250.—Graphs showing density and kinematic viscosity of steam and air at different temperatures.

in. of such material. All metal surfaces should be painted before the covering is applied. Canvas held in place by iron or brass bands is ordinarily placed over the magnesia covering to prevent it from disintegrating. A moderate investment in insulating material will soon be repaid by steam saved. Steam lines from boiler plants to the wells on an oil property are usually buried in the ground. In this case the pipe may be surrounded in the trench with oil sand, which is a very effective heat insulation. When pipes are placed on or above the ground surface, they may be surrounded by a rectangular wooden trough filled with oil sand.

Steam distributing pipes should be carefully graded, if possible, to a uniform slope, so that the condensed water will be gathered at definite points and removed by steam traps or drains. The slope should be in

the direction of the steam flow. Wherever a rise is necessary, a drain or trap should be installed. All main headers and branches should end in a drop leg, and low points may be connected to a drainage pump which returns the condensed water to the boiler plant. Branch lines should be taken from the top of a main header rather than from the bottom. Each engine should have its own separator, placed as near the throttle as possible. Such separators should be drained to the drainage system.

INTERNAL COMBUSTION ENGINES

Gas Engines

Wherever natural gas is available in sufficient quantity, the internal combustion engine, utilizing natural gas as fuel, offers the most economical solution for the power problem. In many cases low-pressure gas is used which could not be adapted to any other useful purpose, and the fuel cost of power development becomes almost negligible.

Gas engines have been chiefly used in well pumping service, for which purpose the horizontal, single-cylinder engine is well adapted. This type of engine is also widely employed in operating compressors, pumps and other mechanical units in the oil fields. In early efforts to adapt the gas engine to drilling service, use was naturally made of the same single-cylinder type of engine that had been developed for pumping service. This was found to be poorly adapted to the requirements of drilling, because of its lack of flexibility in speed and power output. The failure of this type of engine in operating drilling equipment seems to have prejudiced oil operators against all types of gas engines for this purpose, but recent tests made with vertical four-cylinder engines indicate that the larger sizes of multiple-cylinder engines are capable of operating either cable tool or rotary equipment in a satisfactory manner, and at considerably lower cost than is possible with the less efficient steam engine.

The type of gas engine that has been found most successful in operating drilling equipment is modeled closely after the four-cylinder automobile engine, except that it is of higher power and is equipped with a special reversing drum and clutch, a flywheel and an auxiliary starting engine. Two engines of this type have been developed for drilling purposes: the Clark drilling engine,* and the Holt engine.† The Clark engine develops 120 hp., and is mounted on a low truck of special design (see Fig. 251). Constant motor speeds and power output can be maintained from 85 to 500 revolutions per minute. A separate 6-hp. starting engine is supplied with this drilling engine. The Holt drilling unit is

* Manufactured by Clark Brothers, Orleans, N. Y.

† Manufactured by Holt Mfg. Co., Stockton, Cal.

equipped with a 75-hp. engine of the type developed for driving caterpillar tractors. These engines may operate on either natural gas, gasoline or distillate. Both engines have been recently used in the California fields with satisfactory results.* Their greater success in comparison with the horizontal, single-cylinder type of engine is due primarily to their greater power and flexibility. The chief advantage of the inter-

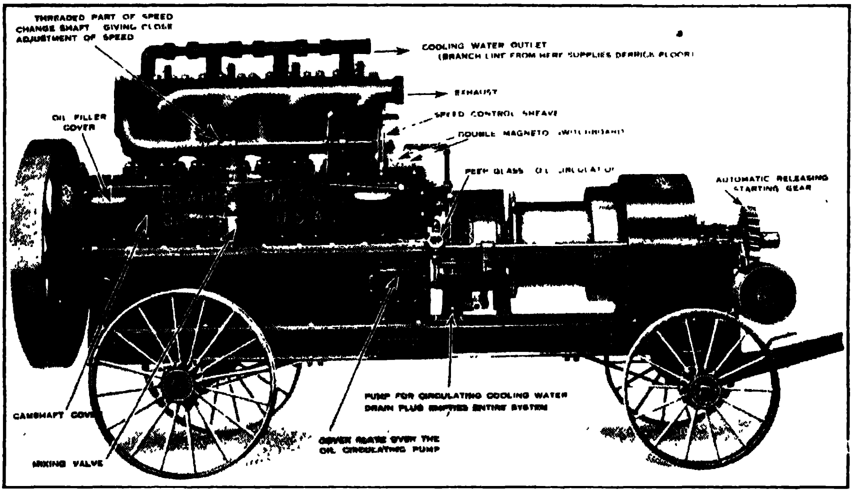


FIG. 251 Clark gas engine for drilling service

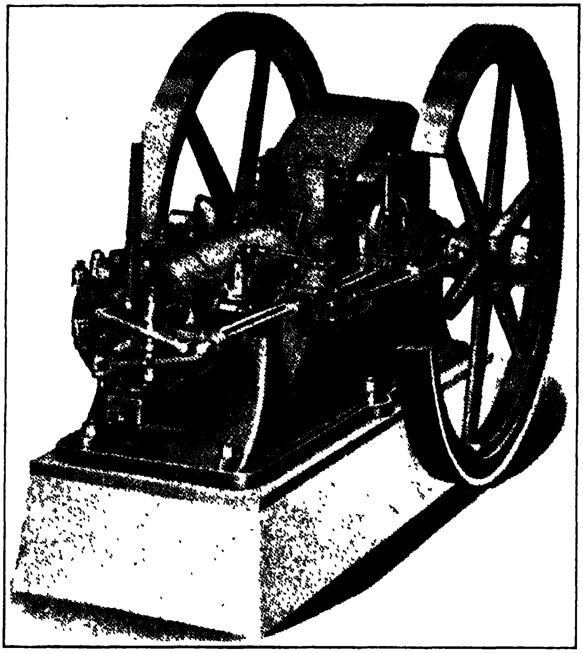
nal combustion engine for drilling purposes lies in its economy. The gas engine requires about one-tenth of the fuel by weight that an oil-burning boiler requires, and comparatively little water. It would appear to be particularly useful in drilling wild-cat wells, where fuel and water transportation are large items of expense.

For pumping service, the engine used may be either of the two-cycle or four-cycle type; that is, it may receive a power impulse with every revolution of the crankshaft in the former case, or with every other revolution in the latter. Considerable variation is found among the many types of gas engines available on the market, in such matters as valve control and arrangement of lubricating devices, governors and ignition systems. They operate at speeds ranging from 180 to 250 revolutions per minute, and have a piston stroke ranging in different types from 12 to 18 in. Units as small as 5 hp. are available, but for ordinary individual well pumping service engines ranging from 15 to 50 hp. are used, the average 2,000-ft. well requiring an engine of about 25 or 30 hp. (see Fig. 252). The pumping of the well does not ordinarily require the continuous

* DEAN, C. J., The gas engine as a prime mover for drilling oil wells, *Thesis* performed under the direction of the author, University of California, 1923.

application of this amount of power, but the engine must have sufficient power in reserve to take care of ordinary repair work.

Gas, preferably dry gas stripped of its gasoline content, is led to the engine through a small gasometer which serves to equalize irregularities in pressure. Engines of the type used in pumping oil wells consume about 12 to 13 cu. ft. of gas per horsepower-hour. Engines of larger capacity may operate on as little as 9 cu. ft. per horsepower-hour. Low-



(Union Tool Co., Torrance, Cal.)
FIG. 252. "Ideal" gas engine for well pumping service.

pressure gas is preferable, 4 oz. pressure being sufficient. The gas and the necessary amount of air are admitted to the engine by the action of mechanically operated valves. For complete combustion 1 cu. ft. of average natural gas requires about 10 cu. ft. of air. The mixed air and gas in the cylinder are exploded electrically or by the "hot-spot" method, that is, by bringing the gas into contact with heated metal in the form of a tube, bulb or point. Electric ignition is more satisfactory. The electric spark may be generated by a make-and-break device, or by means of a magneto. The engine cylinder is water-jacketed and must be cooled by circulating water. This circulation may be attained by gravity if the water is only to be used once, but if water is not plentiful, it may be used repeatedly, flowing in closed circuit between the engine jackets and a near-by water storage tank. In the latter case, the pump necessary to

circulate the water is operated by the engine. A system of forced feed lubrication is a desirable feature in gas engines of this type, requiring another small pump. The pumping engine should be equipped with two large flywheels or balance wheels, to equalize the loads on the engine, and a suitable governor should be provided to throttle the fuel valve in case the engine tends to overspeed with variation in load.

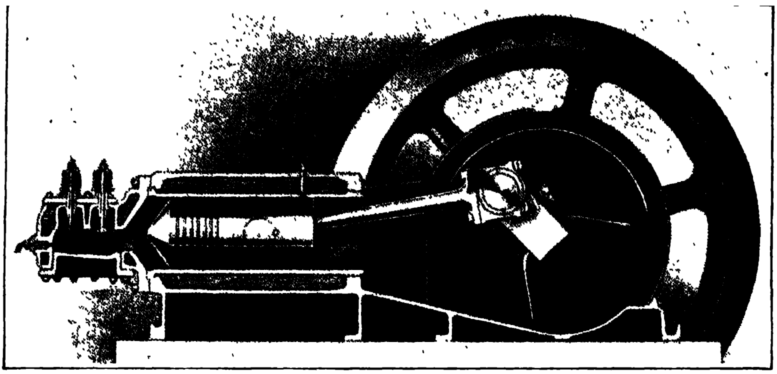
Gasoline Engines.—No discussion of power in oil field service would be complete without mention of the gasoline engine. Though the aggregate amount of power developed by gasoline engines is relatively small in comparison with that developed by steam engines and gas engines, this type of engine is indispensable for certain kinds of service. Such engines are confined largely to automobiles, tractors, trucks and portable well-pulling machines, purposes for which no other form of power is quite as satisfactory; and these devices contribute in no small part to the success of modern methods of oil development and production. The efficiency and adaptability of the type of engine here referred to, and the character of the fuel on which it operates, are matters that are too well understood by the American public to justify further description here.

Oil Engines.—The Diesel type of engine, in which oil fuel is burned within the engine cylinder, is a relatively new type of prime mover that has been undergoing rapid development within recent years. For a time, the complex mechanism and high pressure utilized in the earlier types of Diesel engines made them appear impractical for the rough duty imposed in oil field service, but recent types, more rugged in their construction and operating at lower pressures, have attracted favorable attention. Such engines are now frequently selected as prime movers in electric power generating plants, in operating air compressors, driving oil line pumps and for other similar duties. They are now available in all sizes above 10 hp., but have not as yet been satisfactorily adapted to well drilling and pumping service. Thermodynamically, they are more efficient than any other type of engine, occasionally attaining thermal efficiencies as high as 35 per cent.

The earlier types of oils engines, of which there are many thousands now in service, operate on gas oil, kerosene or engine distillate. They are quite similar to the ordinary gas engine in design, except that they operate under higher pressures (about 50 lb. per square inch) and special devices in the form of hot bulbs, tubes or linings are necessary to vaporize the fuel. With such fuels, properly vaporized, ignition may be accomplished electrically, as in the gas and gasoline engines.

In adapting the oil engine for use with lower grade fuels, such as ordinary fuel oil or even heavy crudes, electric ignition becomes impossible, and reliance must be placed on heated vaporizers and high compression to vaporize and burn the fuel. The vaporizer is in this case a separate chamber connecting directly with the cylinder. All oil is vaporized in the vaporizer, so that only gas enters the cylinder.

Both two-cycle and four-cycle oil engines are available, the method of operation, as between the two types, differing somewhat. In the two-cycle engine, during the power or working stroke, an oil spray is injected into the heated vaporizing chamber, is vaporized and mixed with compressed air in the cylinder, where it burns. On the return stroke, the burned gases are exhausted through suitable valves that open at the end of the power stroke. Such an engine must be equipped for compressing the air necessary to burn the fuel. This is done by the same piston, utilizing the crankcase end of the cylinder as an air compressor, and storing the air either in the crankcase, or in a suitable chamber enclosed in the bed of the machine, and connecting through valves with both ends of the cylinder.



(*De La Vergne Co., New York*)

FIG. 253.—Sectionalized view of De La Vergne four-cycle oil engine.

The four-cycle type is generally preferred since it is more economical and reliable, and compressed air can be dispensed with. In this type (see Fig. 253) there is one power impulse on every fourth stroke. The first is a suction stroke, during which atmospheric air is drawn into the vaporizer and cylinder through a mechanically controlled valve. On the return or compression stroke the air valve closes and the piston compresses all air into the vaporizer to a pressure of at least 280 lb. per square inch. Near the end of the compression stroke, oil is atomized under the pressure of an oil pump into this confined charge of heated air, rich in oxygen, and striking the heated surfaces, vaporizes and ignites. The piston then moves forward on its power stroke under a pressure ranging above 475 lb. per square inch. At the end of this stroke, the exhaust valve opens and the burned gases are exhausted from the cylinder by displacement on the second return, or fourth stroke.

In some types, oil is injected with the air on the suction stroke. Some manufacturers also use a water spray in the cylinder on the compression stroke. This, it is claimed, aids in vaporizing the fuel, and largely prevents the formation of carbon, which tends to accumulate on the vaporizer and cylinder surfaces. Other manufacturers consider that the water spray is unnecessary if a properly designed vaporizer and spraying nozzle is used, and find that the presence of water vapor reduces the efficiency.

Speeds range from 200 to 250 revolutions per minute, and are usually controlled by an automatic governor actuating a throttle valve on the oil feed pipe. Single-cylinder oil engines are usually equipped with two heavy flywheels to equalize the power output. Twin-cylinder engines have only one flywheel.

Oil engines, whether of the two-cycle or four-cycle type, must be started with compressed air; and for starting purposes, a small compressor and separate gasoline

engine must be provided. The fuel oil pump is operated by a hand lever in starting. The difficulty of starting is perhaps the chief reason why the oil engine has not found wider application in oil well pumping and drilling service, though its lack of flexibility in speed and power torque is also a disadvantage. For stationary service, where a fairly constant power is required, the oil engine is well adapted, and its economy in comparison with any other type of engine is unquestionable. Some oil engines deliver a brake horsepower-hour on as little as .4 lb. of oil From 1 gal. of fuel oil 13 to 15 b.hp.-hr. are thus obtained. These results, however, require the best mechanical and operating conditions, and neglect or failure to realize such conditions will result in increased fuel consumption.

ELECTRIC POWER

In many regions oil producers are able to purchase electric power from power companies operating as public utilities. The power may be derived from hydroelectric development in distant mountains, or it may be generated in large and favorably situated and efficiently operated central power stations, using steam engines, steam turbines or internal combustion engines as the primary source of energy. In this case, very favorable rates are obtained, occasionally as low as 1 ct. per kilowatt-hour, and this form of power becomes cheaper than any other. Furthermore, the oil operator is relieved of all of the troubles attending small-scale power generation, as well as the large capital outlay necessary for power-generating equipment. He has available a form of power adaptable to his needs, that can be efficiently transmitted and applied. There is no surplus power; the operator pays only for what he uses.

Where electric power cannot be purchased from outside concerns in this way, it is often possible for the oil producer to develop his own electric power in a plant located on or near the "lease." The economies of large central power plant practice, in contrast with the inefficiency of small scattered plants, the small transmission losses possible, and the relatively low cost of providing and maintaining electric power and distributing equipment, make this a very attractive form of power.

The generating plant may operate on steam power developed by the burning of crude petroleum, fuel oil or natural gas under large boilers. The electric generators are in this case operated either by steam engines or steam turbines, preferably the latter. The over-all efficiency of such a plant may be as high as 11.5 per cent under favorable conditions. The great strides made in the development and application of the internal combustion engine within recent years have resulted in the wide use of gas engines and oil engines as prime movers in central power plants. Efficiencies of 21 per cent are not uncommon in such plants; and they are more economical than steam plants from every point of view.

The generators used are preferably of the three-phase, alternating current type, since the three-phase induction motor has the best character-

istics for oil field work. It is often necessary to increase the power output of the plant as the development of the property proceeds. In this case it is a good plan to install one generator of moderate size first, and later add more units when the number of wells is increased so that more power is required.

The transmission system consists of three wires strung on poles from the generating plant to small transformer stations near the wells. Current of 440-volt intensity is suitable for transmission over moderate distances, but this must be reduced to 110 or 220 volts at the motors in order to eliminate danger to the operator. Special protection against lightning should be provided where electrical storms are prevalent. If the operator purchases power from a power company, he must usually provide his own transmission lines from a centrally located transformer station where the high voltages maintained on the power company's lines (often from 10,000 to 20,000 volts) are "stepped down" to 440 volts, or whatever voltage the operator may find desirable for local distribution purposes. Electric power is not so limited in its range of transmission as is steam—that is, the distance between the generator and motor is of comparatively little significance.

Transformers.—It is more economical to install one bank of transformers to serve all the wells of a group, rather than to provide a separate transformer at each well. Sufficient transformer capacity to provide current for pulling and cleaning purposes as well as pumping must be arranged for; and if separate transformers at each well are provided each bank must have the necessary reserve capacity, while with a centralized group of transformers, only additional capacity for repair work on, say, two wells at once, need be contemplated. The number of wells that can be operated from a single bank of transformers will depend upon their relative grouping and individual power requirements. For drilling purposes it is preferable to have a separate bank of transformers for each motor. They may be mounted on the ground near the motor, thus shortening the heavy secondary leads, or they may be mounted on a wagon that can be readily moved about over the property as occasion may require.

Motors.—The type of motor used will depend upon the service required of it. The character of service varies widely. For drilling purposes, it is essential to provide a motor that will possess flexibility in both speed and pulling torque. The power and speed variation necessary in ordinary pumping service is relatively small, but it is also convenient to use the pumping motor in pulling tubing and rods, and in other repair work, a service which requires more power and greater speed than pumping service. Hence the motor used for operating the wells is usually designed so that it is adaptable to this dual purpose. Motors of variable speed characteristics are also used on portable pulling

machines for facilitating repair work on the wells when the pumping motors are not adaptable to this purpose. The operation of pumping "powers" used in connection with multiple pumping requires a motor of fairly constant speed and power output. Motors used in driving shop equipment, water pumps, compressors, etc., are also of the constant speed type. Oil pumps may require variable speed motors on account of variable pressure conditions in the pipe lines with seasonal changes in temperature.

For cable drilling purposes, an ordinary variable speed, reversible, slip ring induction motor with wound rotor, gives best results. Speed control is effected through the introduction of a suitable resistance in the rotor circuit, adjusted by a controller. One successful type of drilling motor is equipped with an auxiliary controller in addition to the main controller, to give the finer speed adjustments necessary in adapting the movement of the walking beam to the period of vibration of the drilling cable. The main controller alone gives 10 points of speed control; the auxiliary controller cuts in 8 additional points between any adjacent points on the main controller. This gives 88 different speeds. The two controllers are located near the motor, but are operated independently by telegraph cords from the headache post.[9]

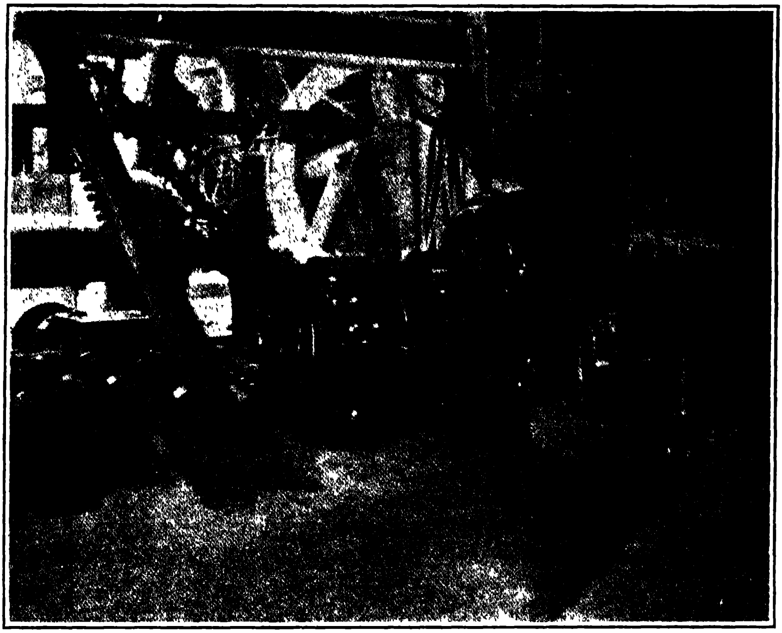
In cable drilling, the beam must overspeed on the down stroke, permitting a free drop of the drilling tools to strike the most effective blow. The motor therefore must slow down on the up stroke and overspeed on the down stroke. This is accomplished by introducing a secondary resistance in circuit when the motor is operated at proper speed.

An ammeter placed in the motor circuit is useful not only in indicating the power consumption during different phases of the work, but serves also as an indication of the amount of strain placed upon the motor and derrick equipment. A recording ammeter is useful also as a check on the efficiency of the drilling crew, and to one skilled in interpreting the records obtained, provides an independent record of the operations in progress and the percentage of time devoted to different operations during each "tour."

For rotary drilling, the same type of motor is used for operating the draw works and rotary table as is recommended above for cable drilling, except that the very fine speed control is unnecessary. The slush pumps are also driven by a separate 50-hp. slip-ring motor, preferably of the same type, though close speed control is not so important here. Rotary drilling places a fairly uniform load on the motor, but the other work that must be done by the same motor, particularly the handling of casing, may be extremely heavy and intermittent in character.

For the standard sizes of cable tool and rotary rigs, a 75-hp. drilling motor has sufficient capacity for the deepest wells now drilled (see Fig. 254). For shallower wells, say less than 2,000 ft. in depth, a 50-hp. motor

is sufficient in many cases. In some foreign fields using other types of rigs, motors as large as 150 hp. have been used. Drilling motors can exert a very high pulling torque, and their ability to do so in an emergency is often important. The motor increases its pull automatically as the load increases, without any changes or adjustments, and develops its maximum pull at dead stall.



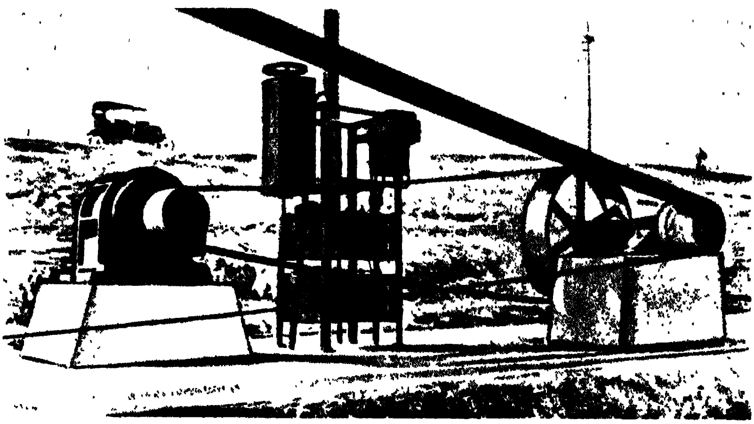
(Courtesy of Union Tool Co., Torrance, Cal.)

FIG. 254.—Electric motor, resistance grids and gear base rigged for rotary drilling.

Pumping service requires, as a rule, practically continuous operation of the motor, with little or no change in the speed or power consumption once the motor is adjusted to the load. A moderate range of speed control is necessary, however, in order to adjust the number of strokes to the variable conditions at each well. To meet the requirements imposed in pulling tubing and rods during repair operations, however, the motor used in operating the well must be able to adjust itself to great variations in speed and load. The two-speed slip ring induction motor with both speeds variable possesses the necessary characteristics for either service.

One commonly used type, designed for the dual purpose of pumping and pulling rods and tubing, has a lower speed of 600 r.p.m., and at this speed, which is used for pumping, is rated at 15 hp. When the motor is to be used in repair work, by simply throwing a pole-changing switch mounted on the frame of the motor, it will deliver 30 hp. and the speed is increased to 1,200 r.p.m. A drum controller and specially designed

secondary resistor give the required speed variation at either high or low speed (see Fig. 255). The motor is protected by an oil circuit breaker which shuts off the power and prevents damage in case the load is suddenly thrown off as a result of breakage or accident. A recording watt meter installed at each well provides a continuous record of the power requirements. Such a record often serves as a useful indication of the condition of the well and the pumping equipment.



(Courtesy of General Electric Co., Schenectady, N. Y.)

FIG. 255. Electric motor, $^{30}/_{15}$-hp., resistance control and counter-shaft used for oil well pumping service.

In addition to the $^{30}/_{15}$-hp. motor, a similar type having a rating of $^{25}/_{10}$ hp. is widely used. The latter serves for relatively shallow wells, while the former has ample capacity for the operation of the deepest wells now drilled. In one of the California fields, one $^{30}/_{15}$-hp. motor is satisfactorily operating a well 4,800 ft. deep.

The actual power consumption in pumping service ranges from 60 to 150 kw.-hr. per well per day, depending upon the depth of the well, the length of stroke, the diameter of the tubing, the number of strokes per minute and other variable factors. It is difficult to calculate the actual power requirement in pumping service because of the many variables involved. For example, a large amount of sand will necessitate the application of an increased amount of power, while on the other hand gas pressure may assist. It is desirable to have some reserve capacity in the motor to take care of changing conditions. The average power consumption for 366 California wells, ranging in depth from 1,000 to 2,500 ft., is 2,600 kw.-hr. per well per month. A group of 82 wells in Kansas, ranging from 2,400 to 2,950 ft. in depth, averages 3,030 kw.-hr. per well per month. In deeper wells of the Goose Creek field (up to 3,400 ft.), the power consumption runs as high as 4,000 kw.-hr. per month.[5]

SELECTION OF POWER FOR DIFFERENT PURPOSES

The selection of one or another of the various forms of power described in the foregoing pages, for any particular purpose, usually requires a close study of operating conditions and relative costs. Generally cost will be the determining factor, but in some cases the peculiar advantages possessed by a particular type of power for a given purpose may offset all other considerations.

For cable drilling purposes, where great flexibility in speed and power output are essential, the steam engine is generally preferred. Though the variable speed electric motor is meeting with increasing favor, few drillers are ready to admit that any other form of prime mover is as well adapted to the purpose as the steam engine. Though high-powered, four-cylinder gas engines have been giving satisfactory results, they cannot as yet be said to have gained the confidence of the majority of drillers and operators.

For rotary drilling the advantage of the steam engine over the variable speed electric motor is not so apparent. Here close adjustments in speed control are not so essential, and the choice depends largely upon a consideration of relative cost. The only disadvantage of electrical power in rotary drilling is the possibility of interruption in service at a critical time by failure of the current. Stoppage of the mud-circulating pumps for more than a few hours' time, with the drill stem in the well, may have serious consequences.

In pumping service, where power in large amount is continually required, the matter of cost becomes of greater importance, and convenience in application is secondary. Furthermore, there is less necessity for variation in speed control. The steam engine under such conditions becomes less desirable than the more efficient internal combustion engine. The low cost and plentiful supply of natural gas in many oil fields has led to extensive use of the gas engine for well pumping purposes. The gas engine offers a very satisfactory type of power for the purpose. Where gas is practically worthless for any other purpose, there is probably no other prime mover that can operate as cheaply. Continuity of the gas supply, however, is a matter that should not be overlooked. Oil producers have frequently invested large sums in gas engines, only to find, a year or so later, that the gas production had declined until there was no longer enough gas to operate them. The oil engine, too, seems well adapted to pumping service, but is too little known and understood as yet to have met with much success. Manufacturers have not as yet given sufficient attention to the building of oil engines in units small enough for oil well pumping. But for simplicity and general efficiency in pumping service, the electric motor is probably the most satisfactory prime mover. Wherever electric current is available at a fair price it has given universal

satisfaction. The reason lies in the relatively low cost of transmission lines and small transmission losses; the low maintenance cost; the saving in operating expense; fewer pumpers are necessary since there are fewer wearing parts, and there is very little about the motor to get out of adjustment. Furthermore, the electric motor is cleaner and quieter; the fire risk is much reduced; there are fewer interruptions in service, and seasonal temperature changes cause no difficulties. It is claimed also that because of its uniform torque, in comparison with other forms of power, there are fewer breakages of the well equipment, fewer "pulling" jobs with their curtailment of pumping time, resulting in lost production.

The greatest advantage of the electric motor in well operation, however, is the ease with which it can be adapted to the work of making repairs. By the mere throwing of a switch, an efficiently operating pumping motor becomes an equally efficient motor for well-pulling purposes. Neither the steam engine nor the internal combustion engine adapts itself so well to this dual purpose. With an engine of either type, we must have sufficient power to meet the heavy demands of well pulling, and for pumping service, requiring less than half as much power, the engine operates far below its rated capacity, with consequent loss in efficiency. With the electric motor there are no stand-by losses. This is one of the fundamental advantages possessed by any form of power which is developed in and distributed from a central power plant, in contrast with separate scattered units. With individual power units, the total power must be equal to the maximum power requirement, and therefore greater than the average power load of centralized plants. The reduction in total power, effected in centralized plants by equalization of "peak" loads, is therefore unobtainable.

Comparative Power Costs.—It is impossible to generalize in the matter of cost. Variation in cost of equipment in different fields and at different periods, variation in cost of fuel or electric power, variations in operating conditions in different fields render cost data pertaining to a given case of little value when applied elsewhere. The engineer must study each case on its own merits before attempting to decide which form of power is cheapest in a given place and for a given purpose. The following figures applying to particular properties are of interest, however:[5]

1. A representative of a well-known manufacturer of electrical equipment offers the following comparative cost figures for pumping wells on an oil property in California on which there are 30 wells ranging from 2,700 to 3,600 ft. in depth, pumped "on the beam," and 65 wells averaging 550 ft. in depth operated by four jack pumping powers. Electric power purchased from a power utility company is figured at 1 ct. per kilowatt-hour; fuel oil is valued at $1 per barrel. No value is attached to the natural gas or water used, it being assumed that they are available on the property and that there is no other market for them. The figures include charges for lost production during shut-downs, as well as interest and redemption charges on invested capital, maintenance, insurance and taxes at average rates.

Comparison of Power Cost of Pumping Oil Wells by Different Methods

	Cost of equipment at wells	Cost of power station equipment	Yearly operating cost
Electric motors, power purchased at 1 ct. per kilowatt-hour	$60,900		$43,707
Electric motors, power generated by steam turbines	60,900	$58,800	49,647
Gas engines	85,500		53,265
Electric motors, power generated by gas engines	60,900	74,500	58,879
Steam engines at wells, including boiler plants burning oil	69,800		152,182

2. A well-known manufacturer of gas and oil engines offers the following comparison of the fuel cost of 1,000 hp.-hr :

Steam engine and boiler, 6 lb of coal per horsepower-hour and 10 per cent stand-by loss	$8 25
Gas engine, 12,500 cu. ft of gas at 30 cts per thousand	3 75
Electricity from central station, 750 kilowatt-hours, at 3 cts	22.50
Oil engines, .75 pint of fuel oil at 3 cts. per gallon	2 81

To this might be added:

Steam engine and boiler, consuming $\frac{1}{4}$ gal. of fuel oil per horsepower-hour at 3 cts per gallon	7 50

3. Another representative of a manufacturer of electrical equipment offers the following comparison between steam and electric power for oil well pumping:

Cost of Pumping 107 Wells, Average Depth 800 Ft., 13.5°Bé. Oil, California Fields

	Cost per well per day	
	Steam	Electricity
Maintenance, pipe lines, wells, pumps, rigs, boilers, motors, transformers and power lines	$ 95	$ 70
Labor, including pumpers, boiler men, electricians and well pulling gangs	65	45
Fuel oil at 35 cts. per barrel	1 17	12
Water, waste and lubricating oil	52	.13
Electric power, assuming 1 ct. per kilowatt-hour	. .	.57
Totals	$3 29	$1.97

4. The following figures[7] indicate the cost of installing a gas engine at a pumping well:*

One 30-hp. gas engine with pipe and fittings	$2,025
One 50-bbl. circulating tank	170
Cement	45
Labor, including foundation, hauling and setting engine	155
Miscellaneous, 5 per cent	120
Total cost	$2,515

5. The approximate cost of installing steam equipment for rotary drilling in the oil fields of southern California in 1922 is shown by the following figures:[7]

One 10- by 12-in. twin-cylinder engine	$1,404
Cost of setting engine (labor, material, hauling)	225
Steam lines	90
Water lines	150
Three 50-hp. firebox boilers	4,500
Cost of setting boilers (labor, material, hauling)	375
Two 12- by 6¾- by 12-in. slush pumps	2,028
Cost of setting slush pumps (labor, material, hauling)	250
One 50-bbl. circulating tank	170
Total cost	$9,192

6. The cost of installing the usual steam equipment for cable tool drilling in the California fields in 1922 was approximately as follows:[7]

One 30-hp. 12- by 12-in. steam engine	$ 750
Cost of setting engine (labor, material, hauling)	150
Steam lines	80
Water lines	150
Two 40-hp. tubular boilers	2,800
Cost of setting boilers (labor, material, hauling)	450
Total cost	$4,380

7. The following figures show the cost of installing and operating electrical equipment for drilling by cable tool method to a depth of 2,240 ft. in southern California, 1922:[7]

Initial cost of motor	$1,625
Cost of installation, including belting, etc	768
Total cost of power equipment	$2,393
Total cost of electric power	575

8. The approximate costs of electric equipment for a rotary drilling rig in southern California in 1922 are as follows:[7]

One 75-hp. drilling motor with all equipment, including connections and reducing gear	$3,900
Cost of installation of motor (labor, hauling, material)	150
One 50-hp. motor for slush pumps, complete	1,600
Two power-driven slush pumps, 6¾ by 12 in., with belt and pulleys	5,250
Cost of installation of motor and slush pumps (labor, hauling, etc.)	190
One 50-bbl. circulating tank	170
Total cost	$11,260

* Southern California fields, 1922.

9. The power consumption of an electrically operated rotary rig can be estimated from the following figures which represent averages for a number of different rigs in various western fields:*

	Kilowatt-hours per 24 Hr.
1,000-ft. territory	150 to 170
1,500-ft. territory	180 to 215
2,000-ft. territory	200 to 235
2,500-ft. territory	230 to 270
3,000-ft. territory	250 to 285
At greater depths than 3,000 ft.	265 to 350

10. The following data furnished by a California oil company show the power costs when drilling by any of three different methods:[7]

Power	Location	Footage drilled	Cost per hour
Motor	California	5,108	$ .45
Clark gas engine	Texas	5,208	.87
Steam engine	Texas	4,000	1.00

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CHAPTER XV

GATHERING, LOCAL STORAGE AND SHIPPING OF PETROLEUM; GAGING, SAMPLING AND TESTING

Some preparation in the way of storage facilities should always be provided near a well before the oil sand is penetrated. Sufficient storage should at least be provided to take care of the ordinary production of an average well for the locality. Of course, there is always some uncertainty about what the initial production of a well will be, and in many cases there may be some doubt about whether the well will produce any oil at all. In such cases the cost of constructing initial local storage should be kept at a minimum in order to avoid unnecessary losses in case the well fails to produce oil. In drilling on "proved land," however, one may be practically certain that the well will produce, and as the drill approaches the horizon where the oil sand is expected, some preparations are usually made to take care of the anticipated production.

Judgment in the amount of storage to provide for may be based upon the experience of neighboring wells in the vicinity. If the conditions are such that a gusher may be expected, with a large initial production, larger storage facilities will of course have to be provided than if a relatively low production is the rule in the particular locality.

In addition to estimating the quantity of oil for which to provide storage, it is necessary to take into consideration the gravity of the oil the well is expected to produce, in order that the character of the storage facilities may be determined. A light-gravity oil requires special precautions in the way of protection against evaporation losses. In a heavy oil district, on the other hand, such precautions are not so essential.

Before the well is "drilled in," and at the time the local storage is constructed, preparations should also be made and under way for connecting the storage facilities at the well with the main collecting system that carries the oil to a larger centralized storage. This is usually provided at some point conveniently situated near the dehydrating plant, or near some shipping point. While it may not be necessary actually to lay the pipes and connecting lines, sufficient pipe should be on the ground ready to connect, and the plans well formulated for its installation, so that the tanks at the well may be connected with the main storage tanks before the capacity of the former is overtaxed.

The storage facilities provided at the well consist either of steel or wooden tanks, or of earthen or concrete-lined sumps. Sumps are generally not covered, while tanks are usually roofed over.

Sumps.—An open sump is the cheapest type of local storage, and is the kind usually provided in low-gravity oil districts where evaporation losses are not a serious consideration. Open sumps are often constructed by simply scooping out a little of the surface soil near the well, with pick and shovel or scraper, and piling the earth so removed around the excavation to form an embankment that will further increase the storage capacity. Sometimes natural depressions in the vicinity are utilized for sump storage. Perhaps no preparation of the ground will be necessary; occasionally a small dam across a gulch or dry stream bed will be sufficient.

Such a sump should be situated as near the well as convenient, and if the ground is at all sloping, it should be on the down-hill side in order to gather all seepage and drainage that is bound to occur around the mouth of the well, especially during the operations of pulling tubing and cleaning.

There are several objections commonly raised against the use of open earthen sumps. It is evident that there are apt to be excessive losses due to evaporation of the lighter and more valuable constituents of the oil, by contact with the air and by the heating effect of the sun. There must also be considerable loss due to seepage through the earthern banks and bottom of the sump. Furthermore, the oil may become contaminated with small particles of earth; and in time of rain, much surface and ground water will also find its way into the sump, causing more or less loss of oil in the subsequent separation of the water from the oil, and danger of overflow caused by floods.

Evaporation losses from earthern sumps may be reduced somewhat by constructing a roof or cover over the pool. This also is effective in keeping out rain; and ground water may be controlled, even during a flood season, by proper drainage around the sump, that is, by digging small ditches around the sump to collect and carry off the surface waters.

Seepage losses will be reduced to a considerable extent by a proper preparation of the inside surface of the sump. Clay is generally used for this purpose, being rammed or rolled into a smooth, impervious lining that prevents much of the loss of oil that would otherwise take place through an earthen or sandy bottom.

It is apparent that the greater the surface area exposed by an oil sump to the atmosphere, the greater will be the losses by evaporation. Evaporation losses from a sump may therefore be reduced, keeping the volume of the sump constant, by making the sump deeper and exposing less surface to the action of the sun and air. Losses due to seepage, on the other hand, increase directly with the area of the sides and bottom exposed to the oil, and the area so exposed to seepage will be greater for a deep sump of relatively small evaporation surface than for a shallow sump of large superficial area of the same capacity. The extra cost of

constructing deep sumps of small surface area is an important item that prevents as much attention being given to the building of sumps as the magnitude of the evaporation losses would seem to warrant.

Light oil standing in open earthen sumps has been known to shrink as much as 40 per cent in the course of from 15 to 20 days. Oil between 33 and 34° in Baumé gravity, standing in open tanks exposed to the air and sun for only 24 hr., has been known to lose 4 per cent of its original volume by evaporation alone; and when it is remembered that these losses represent the lighter and more valuable constituents of the oil, it is apparent that their reduction is a matter well worthy of serious consideration. One reason why the producer does not take greater interest in evaporation losses of oil is that he often receives the same price per barrel for his oil regardless of its gravity. In the low-gravity oil districts of California, for example, 17°Bé. oil commands no higher price than does 14° oil; the loss of a few points in Baumé gravity therefore means little to the producer. It is simply an economic loss that the refiner or consumer ultimately pays by using a poorer grade of oil. Loss in bulk, however, is another matter, representing a direct loss to the producer of a certain percentage of his product.

Another point worthy of note in the discussion of open sumps is the increased fire risk. There is often more or less gas on the surface of such sumps, ready to flash at the slightest spark and set fire to the entire pool. When such a fire once starts, there is little chance of stopping it, and it means the loss of at least the oil in the sump, and in addition, the danger of setting fire to the near-by well and derrick. On account of the fire risk, the sumps should be placed at least 100 ft. from the well, and the intervening space should be kept free from dry grass and other vegetation.

While the disadvantages of sump storage are fully recognized by most producers, it is occasionally the only feasible plan for gathering the oil as it flows from the well. For example, if large quantities of sand or water are produced with the oil, the sump offers a ready means of settling the impurities that may not be as economically effected by any other method.

Provision must be made for draining water from sumps used for oil storage. Oil, being lighter than water, will of course float on top of it, so that as the quantity of water in the bottom of the sump increases, the available storage space for oil decreases. The bottom of the sump is given a slight slope, and the water collects at the lower side and may be drained off through a pipe suitably placed to tap the lowest stratum of liquid (see Fig. 256). When the oil and water may be carried away by the natural drainage, the oil is allowed to overflow into a box from which it enters a pipe leading to the collecting mains. Often the oil is skimmed from the sump by the suction of a transfer pump. Losses of oil carried

away by seepage and overflow from sumps are often serious. Catch-basins constructed in the natural water courses are usually successful in recovering much of the oil. One such catchbasin, situated in a ravine that cuts across the Kern River field of California, recovered an average of 85 bbl. of oil per day for more than 8 years.

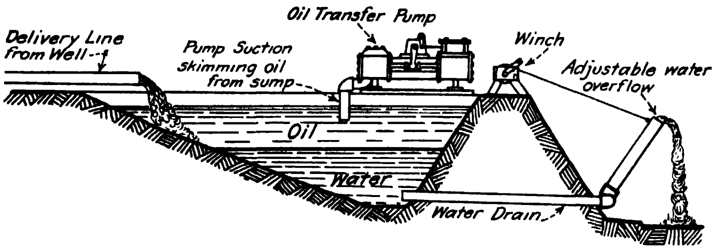


FIG. 256.—Arrangement of sump for continuously separating water from oil.

Tanks for Initial Storage.—Many of the disadvantages of open sumps may be obviated by the use of wooden or steel tanks. Losses due to seepage are reduced to practically zero in such a storage; ground water, rain and dirt may be largely eliminated or prevented from mixing with the oil; and if the tank is properly covered and protected from the sun, evaporation losses will be reduced to a minimum. Such tanks are almost universally used in the high-gravity oil districts where the losses in the lighter and more valuable constituents, which would otherwise be incurred, make such installations indispensable. Tanks are used on the better managed properties, even in the low-gravity oil districts, for they possess other advantages, aside from reduction in seepage and evaporation losses, particularly in the process of gaging and sampling oil, and also in the control and regulation of the gathering system.

Tanks used for the storage of oil at the well are usually small—say, from 25 to 100 bbl. in capacity, occasionally more—and one or more such tanks are placed at each well. It is best to have two tanks at each well, so that if repairs are necessary in one, the other may be used to accommodate the flow from the well while the repairs are in progress. Ordinarily both tanks would be in use, the two being connected by piping and suitable valve control so that they may be used together or as separate units. These tanks are nearly always cylindrical, with the axis of the cylinder vertical.

If the oil contains some water as it comes from the well, a pair of tanks may be utilized to separate a part, or in some cases all, of the water, by pumping all the fluid produced by the well into one of the two tanks, which is utilized as a settling tank. From the top of this tank, clean oil is drawn off into the second tank which serves for oil storage. Periodically, clear water is drained from a tap placed in the

bottom of the first tank until some oil begins to drain off with the water. A drain is usually also provided in the bottom of the second tank to carry off any water that has not had time to settle out in the first. Clean oil is pumped or allowed to flow into the collecting system from the top of the second tank.

These tanks are made of either steel or wood. Wooden tanks are of the wood-stave variety. Metal tanks are usually built of riveted sheet steel or iron; frequently galvanized iron is used, since it resists corrosion better than black iron. The metal used is sometimes in flat sheets, sometimes corrugated. Bolted tanks are widely used for initial storage. In either case the metal sheets are fastened together to form a large cylinder, and the joints are either calked or soldered so that they do not leak. The bottom is flat, is made of riveted sheets and is made watertight in the same way. Further details of this type of tank will be found in Chap. XVII.

A common size of tank used for initial storage is one about 10 ft. in diameter and 8 ft. high, which has a capacity of 100 bbl. A tank of this sort is usually provided with a low conical cover which serves to keep out rain and prevents evaporation losses to a considerable extent. Tanks are often provided with close-fitting covers made of boards and roofing paper. Some sort of a vent in the cover must usually be provided to allow any gas which forms, or which may be pumped in with the oil, to escape. A gage hatch and manhole are also necessary.

Such a tank is often supported on a level timber frame, which serves to give an equal bearing and distribution of the load over the entire bottom, and at the same time holds the metal bottom up off the ground and reduces rusting. Frequently tanks are placed on a carefully graded site surfaced with loose oil sand. A 100-bbl. tank must be well constructed and supported, since the weight of the oil that may be stored in it is about 16 tons.

When a tank is used for initial storage at the well, it is connected directly with the lead line which conducts the oil from the well (see Fig. 202). This direct connection gives a considerable advantage over the usual sump storage methods, in preventing evaporation losses by contact with the air. In the same way a free-flowing well may, by proper arrangement of lines and control of pressures, be made to discharge directly into the storage tank, even though the latter is at some elevation above the mouth of the well.

THE OIL GATHERING SYSTEM

The system of pumps, piping, valves, etc., by means of which oil is transported, and the flow controlled, from the well to a main storage or shipping point, is called the "gathering system" or "collecting system."

Many economies are possible by proper design of the gathering system to secure the maximum advantage of gravity flow, with minimum consumption of power and minimum loss of oil.

When a sump or tank is located in the bottom of a natural depression, or is so situated that its surface is below the level of the point in the gathering system with which it must connect, it is necessary to pump the oil to the point of connection. An ordinary oil well plunger pump is often used for this purpose, operated, perhaps, by a jack and pull line from the near-by rig, an arrangement by which the rig pumps from both the well and the sump. A connection with the end of the walking beam nearest the engine house (in a typical "standard rig") is sometimes provided, so that each end of the beam operates a pump. The auxiliary pump, operated by the rear end of the walking beam, is known as a "tail pump," and is often used when oil cannot be gravitated from the well. Such a pump is usually made out of an old working barrel, no longer serviceable in the well, and is equipped with a standing valve at the lower end, and a leather cup valve above. The whole arrangement is bolted to the main sill of the derrick, in line with the outside end of the walking beam. A polished rod extends upward to the end of the beam, to which it is attached by a stirrup or metal tee, as in the case of the ordinary sucker rod connection.

The tail pump has a 3-in. suction line extending to the near-by sump or small tank, and discharges directly into the collecting system, a check valve being placed at the point of connection to prevent back-pressure. If the well does not produce enough oil to keep the tail pump working continuously, instead of removing or disconnecting it when the sump has been emptied, a by-pass may be installed, leading back to the sump, so that by closing the discharge valve and opening the by-pass valve, the remaining oil circulates in closed circuit with each stroke of the beam. The pump is thus prevented from losing its suction and from drying out. The capacity of such a tail pump is about the same as the ordinary oil well plunger pump of the same size, so that it cannot be used with wells producing more than 350 or 400 bbl. per day.

When a tail pump has insufficient capacity to accomplish the transfer of the volume of fluid entering the sump or tank at the well, it will be necessary to install a reciprocating pump, preferably a duplex oil transfer pump of suitable capacity and design. This may be driven by steam or compressed air, or it may be operated by an electric motor; and it must be capable of developing sufficient pressure to handle the required volume of oil during the coldest season of the year. Figure 257 illustrates a type of oil pump that is commonly used for oil transfer purposes on the "lease."

The oil gathering system must, of course, be designed to fit the conditions imposed in each individual case. The contour of the ground not only has much to do with the layout of the gathering system, but

influences the selection of a site for the dehydrating plant, storage center or shipping point with which it must connect.

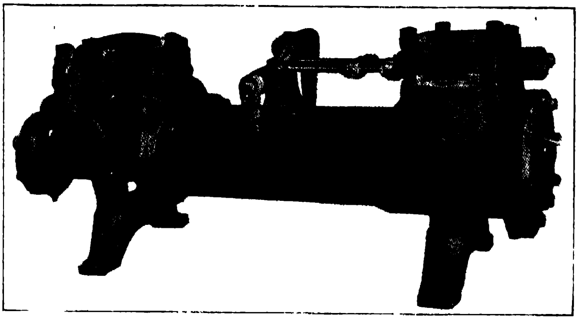


FIG. 257.—Reciprocating pump used for oil transfer purposes.

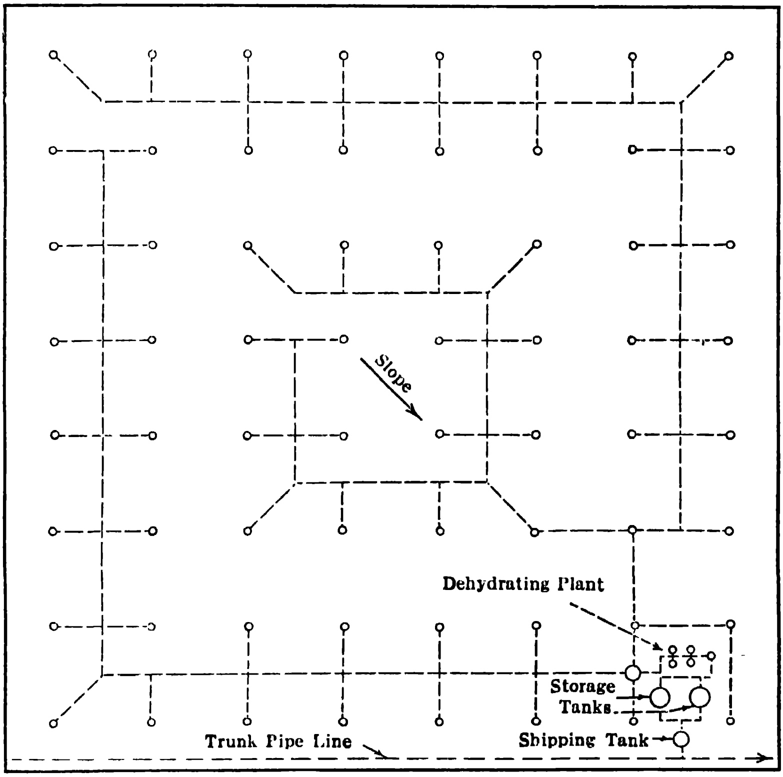


FIG. 258. Ideal gathering system for uniformly sloping terrain.

It is assumed that small receiving and gaging tanks at each well—not indicated in the illustration—are placed at a sufficient elevation to permit oil to flow against the general ground slope for short distances

Since a property is usually developed in a proved oil area by drilling the outside locations first, that is, by "offsetting," it will soon become encircled by a collecting system which connects with the storage tank at

each line well (see Fig. 258). The natural drainage is always toward some one side or corner, and advantage will be taken of this in determining the direction of flow in the pipes and the position of the main storage system. The storage center, dehydrating plant or shipping point should therefore be placed on the lowest corner or side of the property when feasible. Frequently the shipping point is determined by the location of some pipe line already in existence, and the gathering system must lead to what may be an otherwise unfavorable location. The shipping facilities are often under the control of other interests than those which are concerned with the exploitation of the oil property itself, and perhaps one trunk line running along the boundary between two adjoining properties will determine the terminal facilities for operators on either side of the line. One or the other of the two operators must then run his gathering system up-hill, and pumping will be necessary. In such a case, the best practice would usually be to drain such portion of the field as may be effected by natural drainage, to the shipping point, and allow the oil from all other wells to drain into a large storage provided at the lowest point on the property. The oil may then be pumped up to the shipping point by an efficiently operating steam or electric pump, large enough to handle the total volume. Such an arrangement is preferable to the operation of a number of small inefficient pumps located on different parts of the property.

The mains of the gathering system must be of sufficient size to carry the production of the property, or that portion of it which they serve, though if sufficient initial storage is provided at each well, it will probably be unnecessary to draw from every well at the same time. The tanks for initial storage at the well should be of adequate size to take care of the production of the well for say, one day; and the gathering system will probably be able to carry this off in an hour or so. During the remainder of the day, the main gathering lines will be utilized in draining oil from tanks at wells on other parts of the property. The collecting mains will therefore not be drawing from more than a few wells at any one time, but it is apparent that any particular part of the gathering system must have a daily capacity somewhat in excess of the aggregate daily capacity of the wells which it serves.

In some instances where oil wells are located on hilly ground, deeply cut by small streams, the design of a gathering system becomes a difficult matter. One main may serve only two or three wells, and the laterals become extremely irregular in length and direction. In flat territory the necessary head to cause a flow in the collecting system is provided by placing the initial storage tanks at the wells on platforms 10 ft. or so above the ground.

The sizes of pipe used in constructing the gathering system will vary with the volume of oil to be transported, with its viscosity and the

pressures which may be applied either through the instrumentality of pumps or by the action of gravity. The factors determining the quantity of oil that may be transmitted through a given pipe under stated conditions, and the selection of pipe sizes and pressures to transmit a given volume, are discussed in detail, and formulae for their determination are offered in Chap. XVIII.

The pipes are usually buried a foot or so in the earth in order to protect them from the hot sun which causes undue expansion in the line, and from low winter temperatures which cause contraction and which also prevent

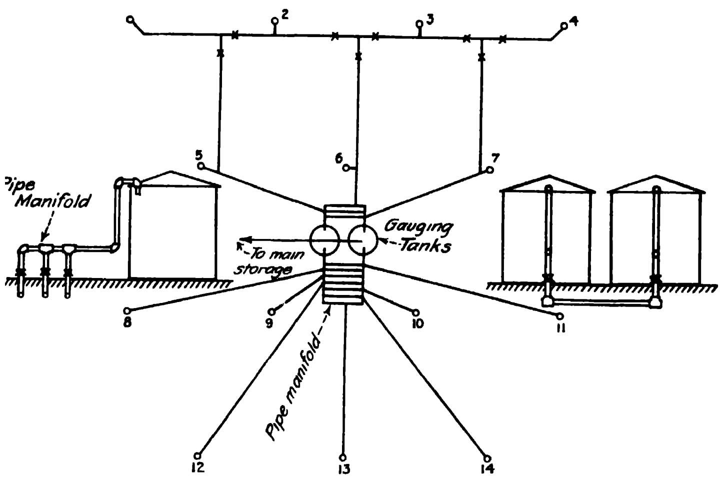


FIG. 259.—Arrangement of gathering lines for connecting a group of wells with a pair of small tanks.

One of the two tanks is used for storage while the other may be used for gaging the flow from each well of the group in succession A suitable pipe manifold accomplishes diversion of the flow from any well to one or the other of the two tanks.

the oil from flowing readily due to increased viscosity. The lines should be carefully graded and their position with respect to the topography so selected that there will be the fewest possible number of depressions or low points in the line that will not be fully drained by gravity flow.

Some gas is almost certain to find its way into the gathering system, and when necessary or convenient, blowoff valves should be provided to relieve the gas pressure. The gas will tend to accumulate at the crests or high points in the line, and blowoff valves should preferably be located at such points. A check valve must usually be placed in every lateral of the collecting system just before it connects with a main, in order to prevent oil from flowing into the lateral from the main in case of inequalities of pressure. Adequate valve control is a very desirable and necessary feature in every gathering system, for there must be means of shutting off any well or group of wells at will, and individual control of each lateral in case of necessity.

The provision of individual oil storage tanks at each well is regarded as a needless expense by many operators, who content themselves with a smaller number of larger tanks, each being conveniently situated to provide temporary storage of the oil from a near-by group of wells. Lead lines from the wells lead to the nearest tank, and the gathering system connects the several tanks with a main storage center. In such cases it is often impossible to gage accurately the production of any individual well of the group, and one of the most useful features of unit control and individual well records is sacrificed. However, if each well is connected with the initial storage tanks by a separate lead line, it will be possible—if two tanks are available and adequate valve control is provided, to divert the flow of each well for a time into one of the tanks which serves as a gaging tank. The other tank of the pair receives the flow from all other wells of the group while the gaging tank is in use. By periodically gaging each well in turn in this way, adequate production records for most purposes can be obtained (see Fig. 259).

GAGING, SAMPLING AND TESTING OF CRUDE PETROLEUM

Duties of the Oil Gager.—The oil producer finds it necessary to employ one or more individuals called "gagers," who are charged with the duty of making such measurements of oil as may be required, with the gathering of samples of the oil, and testing them to determine quality. It is necessary to make measurements of the volumes of oil run from the producer's tanks to pipe line companies or other purchasers, in order that proper financial adjustments may be made between the buyer and seller. The quality of the oil, that is, its gravity and freedom from water and suspended solids, is equally important, inasmuch as values are often based on density and payment is only made for "net" oil or oil free from impurities. Furthemore, many pipe line companies refuse to accept oil containing more than a certain allowable percentage (usually 2 or 3 per cent) of impurity. In addition to measurement of the gross oil production and shipments of a property, inventories of oil in storage, etc., it is desirable to have a means of recording the quantity and quality of the oil produced by each well. Such a record is of great assistance in making valuations of the property, in distinguishing between the profitable and unprofitable wells of a group and in making studies of water incursion. Such individual well production records are required by law in California.

Gaging in Vertical Cylindrical Tanks.—It is customary to determine oil volumes by measurement in vertical cylindrical tanks of known capacity. Tank tables, prepared by carefully "strapping" or measuring the tank, show the capacity for all depths of fluid. There is usually a layer of water, emulsion and solids ("B. S." or bottom settlings) in the bottom of

the tank, the volume of which must be deducted from the measurement of gross volume, as indicated by the top oil surface. In addition, there may be water, emulsion or solid substances in suspension in the oil, their amounts being determined by sampling and centrifuging. The percentage of these impurities, known as the "cut," is multiplied by the total apparent volume of oil to determine the amount of a further deduction. The net result after these deductions from the gross fluid content of the tank gives the volume of clean oil.

Preparation of Tank Tables.—In order to have a means of readily determining the volume corresponding to any depth of fluid in the tank, tables are prepared which give the capacity in barrels for each $\frac{1}{8}$ in. of depth. In preparation for this, the tank must be carefully measured or "strapped." The problem of preparing the table is complicated by the fact that the tanks are seldom true cylinders. Furthermore, the tank foundations may have settled irregularly so that the oil stands at slightly greater depth at some points than at others. Measurements of the outer circumference of the tank are made with a steel tape at one or more levels, usually at the top of the second ring and occasionally at the top of each ring. From these outer circumferences and the known or measured thickness of the tank shell, the corresponding inside circumferences can be calculated. This is conveniently accomplished with fair accuracy by deducting .033 ft. for each $\frac{1}{16}$ in. of thickness of the tank shell, from the outer circumference expressed in feet. Depth measurements are also made on the outside of the tank at several points, measuring, in the case of a riveted steel tank, the vertical distance between the top of the upper flange and the bottom of the lower flange.

The following formulae are used in calculating tank volumes.[1]

$$C^2 \times 0011804 = \text{Barrels per inch of depth.}$$
$$C^2 \times 0001475 = \text{Barrels per } \tfrac{1}{8} \text{ in. of depth.}$$
$$C^2 \times 0002951 = \text{Barrels per } \tfrac{1}{4} \text{ in. of depth}$$
$$D^2 \times 011650 = \text{Barrels per inch of depth.}$$

C and D in these formulae are the inner circumference and inner diameter of the tank, respectively, both expressed in feet. The barrel contains 42 U. S. gal. The total capacity of a tank may be determined by the following formula:

$$\text{Total capacity in barrels} = \frac{(\text{Inside diameter in feet})^2 \times (\text{Depth in feet})}{7.15307}$$

In the case of steel tanks, the volumes are calulated on the assumption that the tank is a true cylinder, of the average circumference measured for the particular cross-section during the "strapping" process. If there has been any noticeable variation in circumference at different levels, the proper circumference to use at any particular cross-section may be determined by interpolation between the measured circumferences. Wood-stave tanks, which are often used for storage and gaging purposes in the mid-continental and gulf coast fields, are made somewhat larger at the bottom than at the top. In this case, the tank is in the form of a truncated cone,

but for simplicity the ⅛-in. volumes are calculated as horizontal segments of a cylinder having the average diameter of the conical segment. Corrugated iron tanks offer some difficulty in determining average circumferences due to the variations introduced by the crests and troughs of the corrugations. The average diameter can be approximated, however, from the depth of the corrugations, and since such tanks are usually of small size, the errors resulting from slight inaccuracies in measurement of average circumference are not great.

In preparing the tank tables, volumes for each ⅛-in. horizontal cross-section are calculated, beginning at the bottom and determining cumulative volumes by successive additions of the ⅛-in. capacities. This computation gives the total volume within the cylindrical shell, from which must be deducted the volume of all roof supports and swing pipe connections, to determine net storage capacity. "Deadwood" deductions are computed from carefully made measurements of all objects within the tank, their total displacement for each ⅛-in. interval determined and the amount deducted from the corresponding gross capacities. A 55,000-bbl. tank with wooden roof supports will generally have between 700 and 800 cu. ft. of deadwood to be deducted in this way from the gross volumes, in determining net storage capacity.[1]

To facilitate depth measurements in a concrete reservoir or large concrete tank having sloping sides and bottom, a "gage plate" is usually set in the concrete bottom as near the lowest point in the reservoir as may be feasible.[1] Such a plate is 2 or 3 ft. square and is carefully leveled. Directly above, in the reservoir roof, the gage hatch is located, and sometimes a perforated pipe is provided, extending from the gage plate to the hatch. This serves as a guide for the plumb bob and tape. Tables are prepared showing the capacity of the reservoir for all elevations above the gage plate. Since it is not usually possible to place the gage plate at the lowest point in the reservoir on account of the danger of accumulation of sediment, the sloping bottom and swing pit will contain considerable oil which may be below the gage plate, and therefore unmeasurable. In order to determine the amount of storage capacity below the gage plate, careful measurements are made before the reservoir is placed in service. The elevation of various points well distributed over the bottom is determined with the aid of a level and rod, and a contour map is prepared, from which the capacity for each 1-in. increment of depth is calculated. If the reservoir is circular in form, the sloping sides above the gage plate may be treated as the frustrum of a cone in the calculations, and circumferences averaged for each ⅛-in. interval. Elliptical or irregularly shaped reservoirs can best be dealt with by developing a complete contour map for the entire reservoir, the sides as well as the bottom, graphically determining areas within successive contours with the aid of a planimeter. If the side slopes are fairly uniform, the contour interval may be 1 ft., intermediate horizontal cross-sections at ⅛-in. intervals being computed by interpolation.

The gage tables may be prepared in either of two ways. The customary method consists in giving volumes by increasing progressively upward above the bottom of the tank as a datum or level plane, marking zero volume. The volume indicated by the table for the top surface of the oil gives at once the gross volume of fluid in the tank. Some operators prefer the second type of table, which gives volumes increasing progressively below an established datum at the top of the tank. These are called "outage" tables. They really indicate the volume of air space above the oil. Such tables are generally used in connection with "shipping" tanks, which are used to measure the oil run from the tank into a purchaser's pipe line. The oil run is always the volume obtained by the difference of two measurements, one at the beginning of the "run" and the other at the end. The fluid in the tank is seldom entirely drained. For such purposes the outage table is more convenient, inasmuch as the necessary measurements of oil level can be made without the necessity of lowering a measuring device through the oil to the bottom of the tank.

Temperature corrections are not always applied in the field measurement of crude oil volumes, though when a large volume of oil is gaged at unusual temperatures a considerable error may be introduced. It is customary to deduct 1 per cent from the measured volume for each 20° above 60°F. An equivalent correction is added for each 20° below 60°F. This is based on an assumed average coefficient of expansion of .0005, which is a fair average for Pennsylvania oils. Though commonly applied elsewhere in the United States, this figure is too high for California and other low-gravity asphaltic base oils. For California oils, an average coefficient is about .00038, which is equivalent to a correction of 1 per cent for each 25° change in Fahrenheit temperature. The coefficient, however, will vary for different oils, and for the same oil at different temperatures. Hence, if accuracy in measurement is important, the coefficient of expansion of the particular oil at the temperature of measurement should be determined.*

Depth Measurements.—In determining the depth of fluid in a tank, it is customary to lower a heavy plumb bob on the end of a steel tape, until it just touches the bottom of the tank. A heavy bar of metal must be used as a plumb bob when dealing with very viscous oils. If a light plumb bob is used, there may be some slack in the tape so that too great a depth of fluid is recorded. On being withdrawn, oil clings to the tape, leaving a mark from which the position of the oil surface may be determined. If a piece of the tape has been cut off corresponding to the length of the plumb bob, the lower end may be made zero and a direct reading of the depth of fluid obtained from the tape graduations. Depth measurements must be carefully made, especially when gaging oil in large tanks. In a 55,000-bbl. tank, an error of only ⅛ in. in depth measurement means an error of 19 bbl. in gross measurement. In small-sized tanks, gage poles or rods are often used instead of the tape. These may be graduated in the same manner as the tape or they may have only the foot marks indicated on a rough scale, closer measurements being made with a tape or a short wooden scale graduated to read to eighths of an inch.

When making measurements of position of the oil surface for use with outage tables, a mark or knife-edge is established at the roof level of the gage hatch, from which all measurements are taken.[5] The tape is lowered, with the heavy plumb bob attached, until a few inches of the plumb bob are immersed in the oil. A scale divided into inches and eighths is attached to or etched on the plumb bob, the scale reading downward from the zero point of the tape which is attached to the top of the plumb bob. With the plumb bob partly immersed below the oil surface, the tape is carefully lowered until the nearest foot mark is brought opposite the knife-edge or other reference mark. The tape is then withdrawn and the reading on the plumb bob scale noted and added to the footage indicated on the tape. The method is indicated

* Bearce, H. W. and Peffer, E. L., Density and thermal expansion of American petroleum oils, U. S. Bureau of Standards, *Tech. Paper* 77, 1916.

in Figs. 260 and 261. An instrument known as a hook gage has been devised to facilitate outage measurements (see Fig. 262). When looking down upon the oil surface, it is easy to note precisely when the point of the hook emerges from the oil surface. The zero point of the tape is on a level with the point of the hook, so that measurements with respect to the datum mark are read directly on the tape.

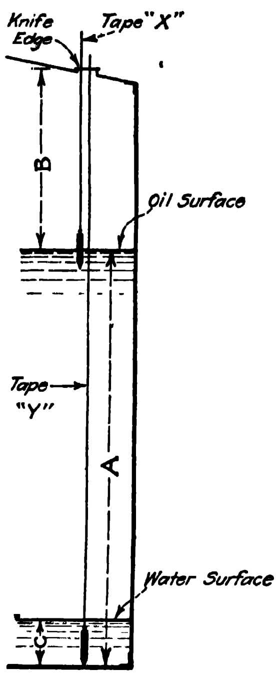


FIG. 260.—Illustrating method of making "outage" measurements.

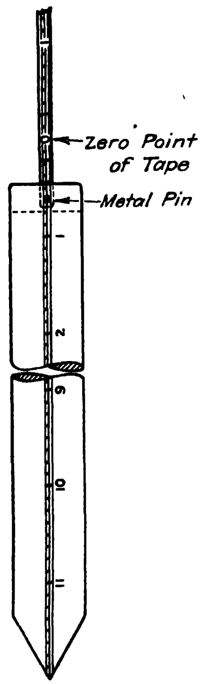


FIG. 261. Steel tape and plumb-bob for oil gaging.

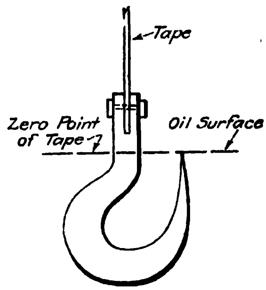
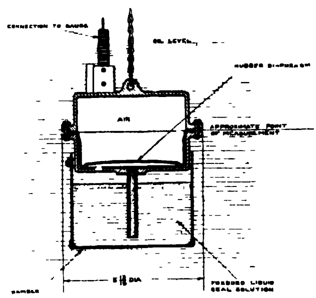


FIG. 262. Hook gage.



(*Foxboro Co, Inc, Foxboro, Mass*)
FIG. 263.—Foxboro liquid depth indicator.

Various types of floats have been devised which are placed within the tank and connected by a system of wires or chains passing over pulleys, with a depth indicator operating between vertical guides against a scale placed on the outside of the vertical shell of the tank. Such devices can seldom be made sufficiently accurate for ⅛-in. measurements, and the floats do not maintain a constant position with respect to the oil surface.

A device for indicating depths or quantities of oil in tanks known as the Pneumercator, has been patented within recent years, and is used to some extent in fuel oil and refinery storage tanks. It has not as yet been used to any great extent by oil producers, and it is thought would not be sufficiently accurate for use in large tanks where accurate gaging is essential. It consists of a small, bell-shaped tank submerged in the oil at the bottom of the oil tank, and open at the bottom to the pressure of the hydrostatic head of oil above it. Air imprisoned within the device is compressed or expanded as the head of oil in the tank is altered. Air connections are made from the air tank by small tubing to a delicate pressure gage which indicates pressure variations to an observer. The pressure so recorded is directly proportional to the depth of fluid, and the gage dial is graduated to read directly in feet and inches. A

somewhat similar liquid level gage is manufactured by the Foxboro Company, Incorporated, of Foxboro, Mass. (see Fig. 263). In this instrument there is provided a flexible rubber diaphragm which separates the air chamber from the oil. The diaphragm, in turn, is protected by the use of a liquid seal, filled with a fluid heavier than oil, which does not attack rubber. Variations in air pressure are recorded through the medium of a small flexible copper tube, on a low-pressure recording gage. The specific gravity of the oil must be taken into account in converting observed pressures to equivalent depths of oil, but this may be done by a mechanical adjustment on the gage. Such an instrument may also be used to indicate variations in gravity of oils, providing a constant head of oil can be secured. An electric alarm bell may also be operated by it to indicate that a tank has reached full capacity, thus preventing loss and damage by overflows.

Water-finding Devices.—For determining the depth of the water layer in the bottom of an oil storage tank, various devices known as "water finders" have been developed. Perhaps the best of these is one which makes use of a strip of paper coated with a yellow-colored material that is soluble in water but not in oil. Such a strip of prepared paper, attached to the plumb bar and lowered to bottom on the gaging tape, will indicate the precise position of the water surface by a change in color of that portion of the strip subjected to contact with the water. Ordinary white chalk rubbed on a foot or two of a gaging pole will, after the pole has been lowered to bottom, also indicate the depth of the water layer. Molasses on the gage rod has been effectively used in the same way. Ebony wood is wetted by contact with water, but not by oil. Hence, a scale made of this material, lowered to bottom, will, on being withdrawn, indicate the depth of the water layer.

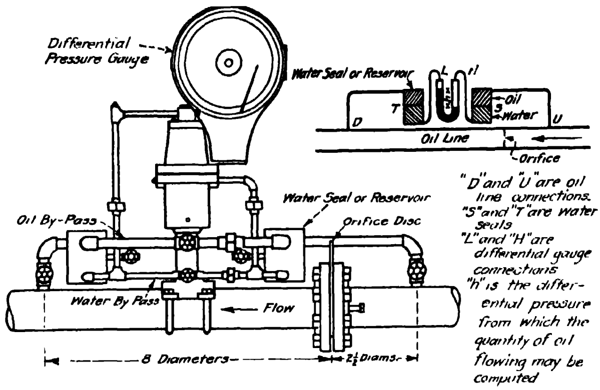
It is seldom necessary to measure a water layer of any great depth in the bottom of an oil tank, since the tanks are usually equipped with water drains through which all but a few inches of the water will be drained off prior to gaging. It is seldom possible to drain the water completely from a tank without loss of some of the oil.

Some attention has been given to the development of a water surface indicator in the nature of a float which is heavy enough to sink through oil, but light enough to float on water. The narrow margin between the specific gravities of water and petroleum has made the design of such a float difficult except in the case of the lightest oils.

Oil Meters.—Attempts have been made to adapt various types of fluid meters to the measurement of oil, but up to the present time with indifferent success. At any rate, no oil meter has yet been developed which approaches in accuracy the precision possible with ordinary tank gaging methods. The high viscosity of most oils at normal temperatures, irregularities in flow characteristics and variations in density are among the variables which make the design of such a meter difficult.

Orifice meters have been adapted to this service, probably with more success than any other type. The loss in pressure after passing through an orifice in the pipe through which the oil flows is continuously measured

and recorded on the chart of a differential recording gage. From the differential pressure so recorded, it is possible with the aid of certain known constants pertaining to the orifice to compute the volume of oil passing the meter. The same type of apparatus is used as is so generally employed in the measurement of natural gas. The only variation introduced is a water seal on each pressure connection, which prevents the oil from coming into contact with the delicate mechanism of the differential gage (see Fig. 264).



(Courtesy of Metric Metal Works, Erie, Pa.)

FIG. 264.—Orifice meter for measuring flow of oil through a pipe.

The Venturi type of meter with differential recording gages, as designed and manufactured by the Builders Iron Foundry of Providence, R. I., has also been used for the measurement of oil.

In meters of the orifice and Venturi types, special constants must be developed for the orifices and tubes used. These vary throughout a wide range with changes in the density and viscosity of the oil. Our present somewhat uncertain knowledge of these constants is one of the factors which prevents a wider use of such meters in the measurement of oil.

Sampling Oils.—Measurement of oil volume is only one of the two factors entering into the determination of value. Quality also must be determined; and for this purpose samples must be collected. Care must be taken to make certain that the samples collected are truly representative of the entire volume of oil sampled. Errors of considerable magnitude may be introduced as a result of careless or improper sampling. For example, in sampling the oil flowing from the lead line of a well, great variations in water content of the oil may be noted.[6] While mixed dipper samples taken at regular intervals over a sufficient period of time may provide a fair average sample of the fluid produced by a well, better results are obtained by running the oil into a small gaging tank and samp-

ling the oil after most of the water has settled out.* Some of the water may be emulsified, however, or may be in such finely divided condition that it remains in suspension for a considerable period of time. Finely divided particles of clay or sand may also remain in suspension. There is a gradual settling of this water, emulsion and solid material toward the bottom of the tank, so that samples taken at various depths will show an increase in impurities toward the bottom, while samples gathered near the top will be comparatively free of water. Oil stored for a considerable time in large tanks or reservoirs will develop pronounced stratification, so that samples must be taken at several depths and the results averaged. Even the gravity of the oil may vary somewhat at different levels, in oil that has stood for a considerable time. Evaporation losses introduce variations in the character of the oil that must be taken into account in determining the density of the oil, and they are often also of sufficient magnitude to produce distinct changes in measured volumes, within comparatively short periods of time (see page 511).

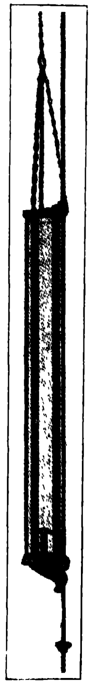
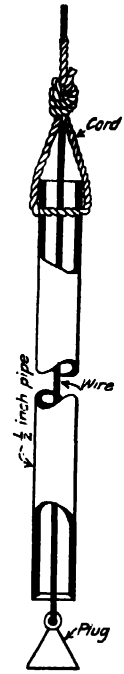


FIG. 265.—Rorrison oil thief.



(After A. W. Ambrose in U. S. B Mines Bull 195).

FIG 266.— Pipe sampler.

For gathering samples of oil from a tank, several types of oil "thieves" have been devised. One of these that is commonly used is the Rorrison thief, which consists of a glass tube mounted in a brass frame and supported by a long chain (see Fig. 265). The upper end is open. On its lower end is fitted a sliding disc valve, actuated by a spring, which closes the lower end of the glass tube. The valve can be set with the aid of a trigger against the tension of the spring, so that the lower end of the tube remains open until the trigger is released by a sharp pull on a wire or cord attached to its control lever. With the valve set in open position and the trigger set, the thief is lowered to the desired level below the surface of the oil, the trigger is then released, the valve closes the lower end of the tube and the sample of oil imprisoned within the tube can be withdrawn to the surface.

Less elaborate devices may be adapted to the same purpose. In tanks of moderate depth, a "core sampler" may be used. This consists of a brass tube or iron pipe, about ½ in. in diameter, and of sufficient length to reach the bottom of the tank. A cork is loosely fitted to the lower end and a wire attached to it in such a way as not to interfere with its use as a plug for the open end of the pipe. The other end

* A method for gaging oil and water at wells, California State Mining Bureau, *Bull.* 84, pp. 89–90.

of the wire is passed through the pipe and held in the hands of the sampler (see Fig. 266). With the cork removed and suspended on the wire a few inches below the lower end of the pipe, the device is slowly lowered through the oil until bottom is reached. By pulling upward on the wire connecting with the cork, the latter is drawn into the lower opening of the pipe; a light blow struck with the pipe on the bottom of the tank drives the cork in securely, and the pipe full of oil, representing a complete cross-section of the oil in the tank, may be withdrawn. Such a sample, when mixed in a suitable container, should be a representative average for the entire tank even though the tank contents have become stratified. A more accurate sample is obtained, however, by mixing several similar samples taken at different points over the oil surface.

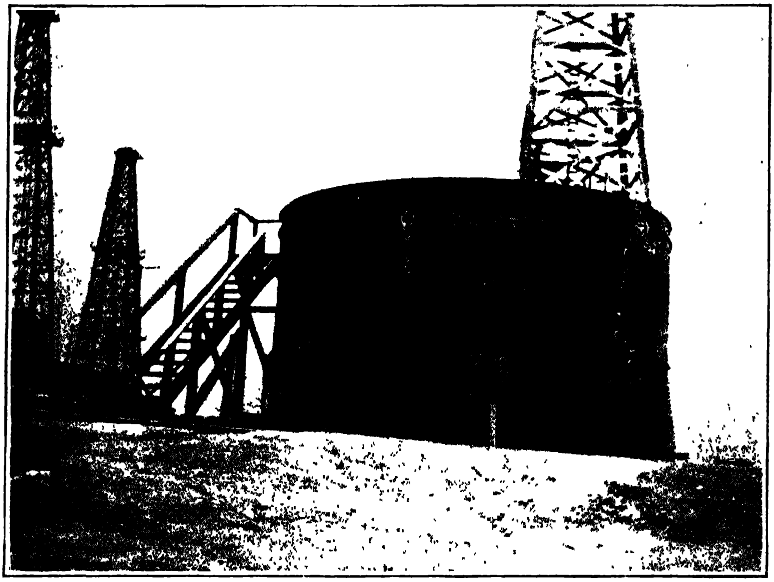


FIG. 267.—A bolted steel tank equipped with sampling cocks.

In some cases where oil is regularly and frequently gaged in a certain tank, as in the case of the so-called "shipping tanks" from which oil is gaged to a pipe line company or other purchaser, special facilities are often provided for securing a representative sample. One method that is commonly used is to provide a series of small pet cocks tapping the tank through the cylindrical shell at uniform intervals of depth from top to bottom (see Fig 267). In this case, by simply opening the valves, conveniently placed near the ground level, one after another, representative samples of the oil at different depths are readily obtained. To permit of gathering samples from different parts of the tank, two or more series of such sampling cocks are arranged at points equidistant around the circumference. The suction valves on shipping tanks are usually locked with a chain and padlock. Drain pipes and valves are conveniently arranged for draining water from beneath the oil, and sometimes gage glasses are connected at two points through the shell of the tank as in a boiler setting, to show the water level.

Protection of Oil Samples. *Oil Containers.*—The samples gathered in the field must be carefully guarded against evaporation losses if they

are to be transported elsewhere before gravity tests are made.[6] Many gagers carry a set of oil hydrometers with them into the field, and make gravity tests on the oil as soon as the samples are collected. This practice avoids evaporation losses and resulting errors in density measurement, but the samples must still be transported to the field laboratory for determining the percentage of water and suspended solids (the "cut"). One hundred cubic centimeters of oil is sufficient for the centrifuge test, but gagers usually bring in samples of pint or quart size for testing. Glass jars with wide necks and metal screw tops, such as are used for preserving fruits and vegetables, are well adapted to short-distance transportation.[7] Such containers leak, however, unless protected by rubber washers, which are soon attacked by the oil. They are therefore not well adapted to the shipping of samples by freight or express. A better type of container for shipping oil samples is a small can with tight-fitting screw cap, which can be tightened securely to prevent leakage. Care should be taken in filling sample containers, to leave an air space into which the oil may expand if subjected to higher temperatures during transit. It is important that each sample be numbered or labeled, appropriately, preferably with securely attached shipping tags, marked with hard pencil, the indentations of which will still be legible after the tag becomes oil stained. Gummed labels are apt to become detached if saturated with oil.

Field Tests Applied to Petroleum

The routine tests applied to crude petroleum by the producer are confined to simple density and centrifuge tests, to determine Baumé gravity and percentage of water and suspended solids. Occasionally distillation tests, viscosity, flashpoint, calorific value and other tests may be applied for special purposes, but the producer's simple laboratory is seldom equipped for these.[8]

Density tests are usually made with an hydrometer suitably weighted for oils of approximately the gravity of the oil to be tested, and equipped with a scale reading to tenths of a degree in the Baumé scale for liquids lighter than water (see footnote on page 5). Each hydrometer has a range of 11 degrees Baumé: 10–21°, 19–31°, 29–41°, etc. They are obtainable in two sizes, one about 8 in. long, requiring only an ounce or two of oil for a test, and the other 12 or 15 in. long, to be used in about 16 oz. of oil. The larger size permits of more accurate readings, and is generally preferred for field use. The instrument used in oil work also contains a thermometer which indicates the temperature of the oil in Fahrenheit degrees. There are two general types of these "thermohydrometers," as they are more properly called (see Fig. 268). The type having the thermometer scale at the top of the stem is to be preferred.

The hydrometer is placed in a glass cylinder or "jar," nearly filled with the oil to be tested, and allowed to sink slowly into the oil until the position of equilibrium is approximately determined. It is then immersed to a depth slightly below this position and allowed to rise under the influence of the buoyant force of the oil until it floats without further vertical movement. The scale reading opposite the oil surface is recorded as the apparent Baumé gravity of the oil. If the color and transparency of the oil permit, the scale reading should be taken at the bottom of the oil meniscus formed by the contact of the oil surface with the glass stem of the hydrometer. If bubbles on the surface of the oil about the hydrometer prevent an accurate reading, they may be dissipated by bringing a drop of ether on the end of a glass stirring rod near them. The thermometer reading should not be taken until the mercury column has risen or fallen to the true temperature of the oil.

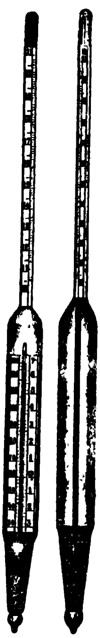


FIG. 268.—Types of thermo-hydrometers.

The standard temperature for gravity measurements of petroleum is 60°F., and if measurements are taken at any other temperature, suitable corrections in the observed readings must be made. The correction to be applied varies with the gravity of the oil and the temperature. No definite relation exists between these variables as far as is known, but tables have been prepared by the U. S. Bureau of Standards* (see Table XXXIX), giving the corrections to be applied over a wide range of densities and temperatures. For oils having a Baumé gravity of about 18°, the correction is approximately 1° for each 20° change in Fahrenheit temperature. For 25°Bé. oil, it approximates 1°Bé. for each 18°F. The correction is added to the apparent gravity if the observed temperature is below 60°F., and substracted when temperatures exceed 60°F.

Other somewhat more accurate instruments that are occasionally used for density determinations when laboratory facilities are available, are the Westphal or specific gravity balance and the specific gravity bottle (see Fig. 269). The former determines specific gravity by measuring the buoyant effect of the oil under test, on a glass plummet of standard proportions which is immersed to a standard depth. The buoyancy is measured directly by accurately proportioned weights and riders, which can be placed at various divisions of a scale along the beam, on the end of which the plummet is suspended. Direct readings to three figures beyond the decimal point are possible with this instrument, but it is not well adapted to the more viscous oils. The specific gravity bottle offers a

* United States standard tables for petroleum oils, *Circular* no. 57, 1916.

TABLE XXXIX.—TEMPERATURE CORRECTIONS TO READINGS OF BAUMÉ HYDROMETERS FOR AMERICAN PETROLEUM OILS AT VARIOUS TEMPERATURES
(Standard at 60°F.; modulus 140)

Observed temperature F.	Observed degrees Baumé							
	20.0	30.0	40.0	50.0	60.0	70 0	80 0	90.0
	Add to observed degrees Baumé							
30	1.7	2.0	2.4	3.0	3.7	4.3	5.0	5.7
32	1.6	1 9	2.3	2.8	3.4	4.0	4.7	5.3
34	1.5	1 8	2.1	2.6	3.1	3.7	4.3	4.9
36	1.4	1.6	2 0	2 4	2 9	3.4	4.0	4.6
38	1.3	1.5	1.8	2.2	2.6	3.1	3.6	4.2
40	1.2	1.4	1 6	2 0	2.4	2.8	3.2	3.8
42	1.1	1.2	1.5	1.8	2.2	2.5	2.9	3.4
44	.9	1.1	1.3	1.6	2.0	2.2	2.6	3.0
46	.8	.9	1.1	1.4	1.7	1.9	2.3	2.7
48	.7	.8	.9	1.2	1.4	1.6	2.0	2.3
50	.6	.7	.8	1 0	1.2	1.4	1.6	1.9
52	.5	.6	.7	.8	1.0	1.1	1.3	1.5
54	.3	.4	5	.6	.8	.9	1.0	1.1
56	.2	.3	3	.4	.5	.6	.6	.7
58	.1	.1	.1	.2	.3	.3	.3	.4
	Subtract from observed degrees Baumé							
60	0	.0	.0	.0	.0	.0	.0	.0
62	1	.1	.1	.2	.2	.3	.3	.4
64	2	3	.3	.4	.4	.6	.6	.7
66	.3	4	.5	.6	7	.8	.9	1 0
68	.5	6	.6	.7	9	1.1	1.3	1.4
70	.6	.7	.8	.9	1 1	1.4	1.6	1.7
72	.7	.8	.9	1 1	1 3	1.6	1 9	2.1
74	8	.9	1.1	1.3	1 6	1 8	2 2	2 5
76	9	1 1	1.3	1.5	1 8	2.1	2.5	2.8
78	1 0	1 2	1 4	1.7	2 0	2 4	2.8	3.1
80	1 1	1.3	1.5	1 8	2.2	2 6	3.1	3 5
82	1 2	1.4	1.7	2.0	2.5	2.9	3.4	3 9
84	1.3	1.5	1.8	2.2	2 7	3 2	3.7	4.3
86	1 4	1 7	2 0	2 4	2.9	3 4	4 0	4.6
88	1 6	1 8	2.1	2.6	3.1	3 7	4.2	4 9
90	1.7	2 0	2 3	2 7	3 3	3 9	4 5	5.2
92	1 8	2.1	2.4	2 9	3 5	4 2	4.8	5.6
94	1 9	2 2	2 6	3 1	3.8	4.4	5.1	5 9
96	2 0	2 3	2 7	3 3	4.0	4 6	5 4	6 3
98	2 1	2 4	2 9	3 4	4.2	4.9	5 7	6.6
100	2 2	2 6	3 0	3 6	4 4	5.1	6.0	6 9
102	2 3	2 7	3 2	3 8	4.6	5.4	6.3	7.2
104	2 4	2 9	3 3	4 0	4.8	5.7	6.6	7.5
106	2 5	3 0	3 5	4 2	5.0	5 9	6.9	7.9
108	2 7	3.1	3.6	4.3	5 2	6 2	7.2	8 2
110	2 8	3 2	3 7	4.4	5 4	6 4	7 5	8.5
112	2 9	3.3	3 9	4.6	5 6	6 7	7.7	8.8
114	3.0	3 4	4.0	4.7	5 8	6.9	7.9	9.1
116	3 1	3 6	4.1	4 9	6 0	7.1	8 2	9.4
118	3.2	3 7	4.3	5 1	6 2	7.3	8 5	9.8
120	3 3	3.8	4.4	5 3	6 4	7.5	8 8	10.1

This table is calculated from the same data as Table II, *Circular* 57, Bureau of Standards

means of determining specific gravity by direct comparison of the weight of a standard volume of the oil in comparison with the weight of the same volume of water. It is a simple and accurate method which is adapted to all grades of petroleum, but is somewhat slower than the other methods

and requires the use of a chemical balance. Temperature corrections must, of course, be applied as in the case of the hydrometer readings, when either the specific gravity balance or bottle is used. The corrections, however, will be expressed in specific gravity units instead of Baumé degrees.

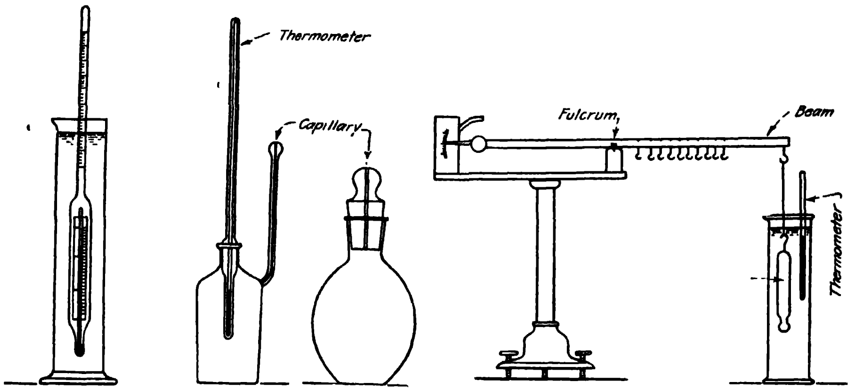


FIG. 269.—Apparatus used in determining density of petroleum.
(a) Hydrometer and jar, (b) Pyknometers or specific gravity bottles, (c) Westphal or specific gravity balance

The percentage of water and suspended solids in a sample of oil is generally determined by centrifuging a measured volume of the oil in a graduated burette. The water and solids, being heavier than the oil, are separated into distinct layers in the bottom of the burette by the selective action of centrifugal force, and their volumes read directly by means of graduations on the side of the burette.

Typical centrifuges, used for making centrifugal tests on oils, are illustrated in Fig. 270. Some are electrically driven, some are operated by steam turbines, some by waterpower and still other types are hand operated. The electrically driven type is preferable. The glass centrifuge tubes vary somewhat in form (see Fig. 270), but should contain 100 cc. of fluid. The upper portion of the tube need only be graduated at intervals of 10 cc., but the lower 15 or 20 cc. in the conical portion of the tube should be accurately graduated to read to tenths of a cubic-centimeter.

Care must be exercised in selecting a portion of the sample for the test. The water and heavier solids tend to settle to the bottom of the container during transportation to the laboratory, and a vigorous stirring may be necessary to secure a homogeneous and representative sample. Then 50 cc. of the oil to be tested are measured into a centrifuge burette and 50 cc. of gasoline, or a mixture of 9 volumes of gasoline with 1 of carbon bisulphide are added. The gasoline serves to reduce the viscosity of the oil so that separation of the impurities is more readily effected. The carbon bisulphide prevents the precipitation of certain solid hydrocarbons by the gasoline, which might increase the apparent percentage of suspended solids. A few

drops of hydrochloric acid are added as a further precaution against this contingency. After corking the burette, the solvent is thoroughly mixed with the oil by agitation. Duplicate tests are run on each sample in order that one may be checked against the other and the two averaged. After removing the corks, the burettes are placed in opposite tube holders on the centrifuge head. Water, or a solution of zinc sulphate, is poured between the glass tubes and their metal holders, to serve as a cushion and prevent breakage of the glass burettes. The weight of each burette and holder, thus prepared, should be carefully determined and any differences in weight as between one burette and another, equalized by varying the amount of water used for cushioning.

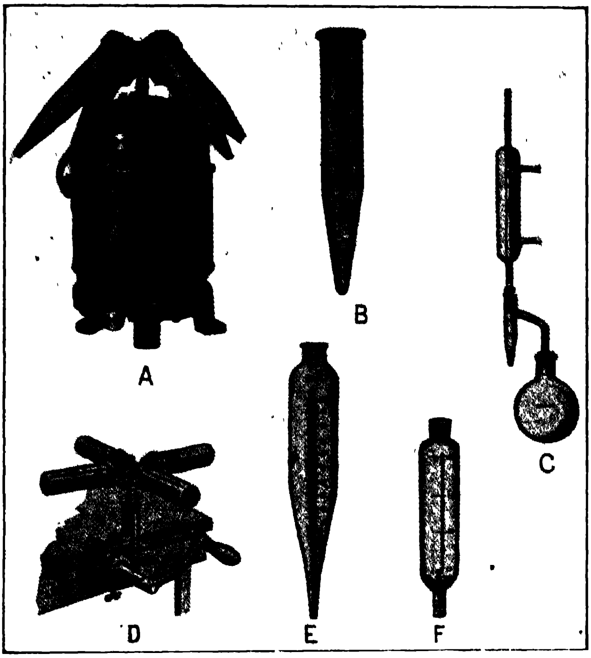


FIG. 270.—Apparatus for determining percentage of water and solids in petroleum. *A*, electrically-driven centrifuge, *D*, hand-operated centrifuge, *B*, centrifuge tube holder, *E* and *F*, types of centrifuge tubes, *C*, Bureau of Mines type of distilling apparatus.

Unless the loads on opposite sides of the centrifuge head are approximately equal, there is apt to be extreme vibration and danger of breakage. The centrifuge should operate at a speed of upwards of 2,000 revolutions per minute. Fifteen or twenty minutes' rotation may be necessary to bring about complete separation of the impurities.

On removing the burette from its holder, the impurities will be found nicely stratified in the bottom of the tube, and volumes can be read off directly by reference to the graduations on the burette. The solid impurities will be in the lowest portion of the burette. Above will be a layer of clear water which represents the volume of "free" water in the sample; and floating on this will be a layer of emulsion, if such is present in the sample. The clean oil, still thoroughly mixed with the solvent, will occupy the remainder of the burette.

Since 50 cc. of oil have been mixed with 50 cc. of solvent, making a total of 100 cc., we have only to double the observed volume in cubic centimeters, of each impurity, to arrive at figures representing their percentages in the original sample. It will be

noted, however, that if emulsion is present that is not broken down by the centrifugal action, the total volume of water will still be unknown (see description of oil-water emulsions on page 493).

It has been found possible to break down petroleum emulsions in the centrifuge test, by the addition of phenol (carbolic acid) to the gasoline-carbon-bisulphide mixture.* One gram of crystalline phenol is used for each 30 cc. of gasoline. Before centrifuging, the tubes, containing 50 cc. of the oil and 50 cc. of the diluent, are thoroughly shaken by hand, and then heated on a water bath at 60°C. for 10 minutes.

A more accurate method of determining the percentage of water in a sample of oil, and one which is effective in indicating the total water content even when emulsified water is present, makes use of distillation apparatus and a specially designed graduated receiving tube (see Fig. 270). Of the oil to be tested 50 cc. are mixed with 50 cc. of benzine or petroleum naphtha, or some other solvent miscible with oil but immiscible with water. The solvent should have a boiling point range extending from a little below to a little above the boiling point of water. The mixture of oil and solvent is heated in the flask, and maintained at a temperature slightly above the boiling point of water until all water present has been vaporized and condensed in the receiving tube. Some of the solvent will also be vaporized and condensed, but will float as a distinct layer on top of the water in the receiving tube. The surplus solvent will flow back into the flask. The solvent serves to reduce the viscosity of the oil and reduces to some extent the boiling point of the water. A little porous tile placed in the flask with the sample prevents "bumping" during the distillation. The volume of water condensed in the receiving tube must be multiplied by 2 to determine the percentage of water present. The method does not indicate the percentage of suspended solids.

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* Dodd, H. V., Determination of water in petroleum emulsions, Summary of Operations, California Oil Fields, vol. 8, no. 5, Nov., 1922. *Eighth Annual Report, California State Oil and Gas Supervisor.*

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CHAPTER XVI

PRELIMINARY REFINING OF PETROLEUM: DEHYDRATING AND SEPARATION OF SAND AND GAS

Crude petroleum, as produced at the well, commonly contains water, hydrocarbon and other gases and various solid substances—mostly sand and clay—all of which must be removed before the product is ready for market. Oil wells differ greatly in this respect—some may produce clean oil or varying quantities of sand with the oil; they may produce oil free from water, or water may be present in varying percentages, sometimes "free," often emulsified; some wells may produce very little gas, while others will produce immense quantities. The extent to which removal of these impurities is necessary will depend upon the requirements of refiners, transportation companies and other purchasers, and upon the customs of the locality in which the oil is produced.

Many pipe line companies will not accept oil for transportation which contains more than 2 or 3 per cent of water and suspended solids (B. S. or "bottom settlings"). Generally the gas will be removed with the aid of a suitable trap located near the well, since its presence causes difficulty in pumping the oil through the gathering mains. If much sand is present in the oil, this, too, will ordinarily be allowed to settle in a sump, tank or settling trough at or near the well, before the oil is taken into the gathering system. Water and the finer suspended solids need not be immediately removed, especially if present in moderate amounts, and may be transported, along with the oil, to a centrally located dehydrating and settling plant.

Separation of Sand.—Sand, which is often present in the oil produced from very porous loosely connected reservoir rocks, may become a source of great annoyance to the operator. The quantity of sand produced will vary within wide limits, being scarcely measurable at times, frequently varying from 20 to 60 per cent of the gross production, while occasionally it will amount to as much as 90 per cent of the material pumped from the wells.* If no water is present, the sand flows freely with the oil, but if water is also present the sand tends to pack, and may become exceedingly difficult to handle in the well and in devices provided for sand separation. As observed in a previous chapter, this sand is often so fine that it passes freely through the screens and accumulates

* Elliott, A. R., Recoverable oil in by-product sands and outcrops, U. S. Bureau of Mines, *Reports of Investigations* no. 2182, Nov. 19, 20.

within the well to the detriment of production. The operator therefore prefers to remove it along with the oil, even though such removal results in greater wear on the pump mechanism, higher power consumption and subsequent cleaning expense.

If the volume of sand produced is small, it may be permitted to settle in one of a pair of receiving tanks located at each well, primarily for preliminary storage and gaging of the oil. In the case of closely spaced wells of small productivity, a pair of 100-bbl. tanks may serve a group of near-by wells. When sand has accumulated to a certain depth in one tank, the flow may be diverted to the second, while the former is drained and the sand excavated by shoveling. Moderate amounts of sand may also be taken care of in certain types of gas traps and dehydrators.

If the quantity of sand produced is such that its removal from tanks or other containers becomes expensive, it may be necessary to lead the fluid from the well into an open earthen sump in which the sand settles and from which the oil is drained or "skimmed" off by the suction of a pump. Excessive seepage and evaporation losses may result from this procedure, and many producers prefer to erect a low-edged wooden trough, built to a very slight slope, through which the oil slowly flows, depositing its sand in the bottom of the trough. Deposition of the sand may be facilitated by riffles or baffles placed in the bottom. Occasional shoveling of the accumulated sand from the trough will suffice to keep it clear (see Fig. 227).

Separation of Gas from Petroleum

Every oil well produces a certain amount of gas, the quantity varying within wide limits for wells in different localities, and at different periods within the life of the well.

Distinction is made between two types of gas produced by oil wells. There may be a considerable volume of gas produced between the well tubing and the inner casing, which rises from the oil-producing horizon through the accumulated fluid in the well to the casing head, from which it is led through the side outlets to the gas-gathering mains. This is called "casing head gas." In some cases this gas has its source in a porous formation penetrated by the well at some distance above the oil sand; and the well may be so cased that the gas rises between the "strings" of casing, perhaps never coming into actual contact with the oil produced through the innermost well tubing. In addition to gas produced free of oil at the casing head, there will always be some gas produced through the tubing along with the oil. This gas, entrained, occluded or dissolved in the oil, may be conveniently termed "lead line gas." If present in quantity and under pressure, it tends to free itself from the oil when the pressure is reduced, forming "gas locks" in the

gathering system, which cause difficulty in pumping the oil, or it may accumulate in dangerous quantities in the oil storage tanks. The producer will find it advisable to separate this gas from the oil as soon as possible after it leaves the well, by passing the oil and gas through a suitable gas trap.

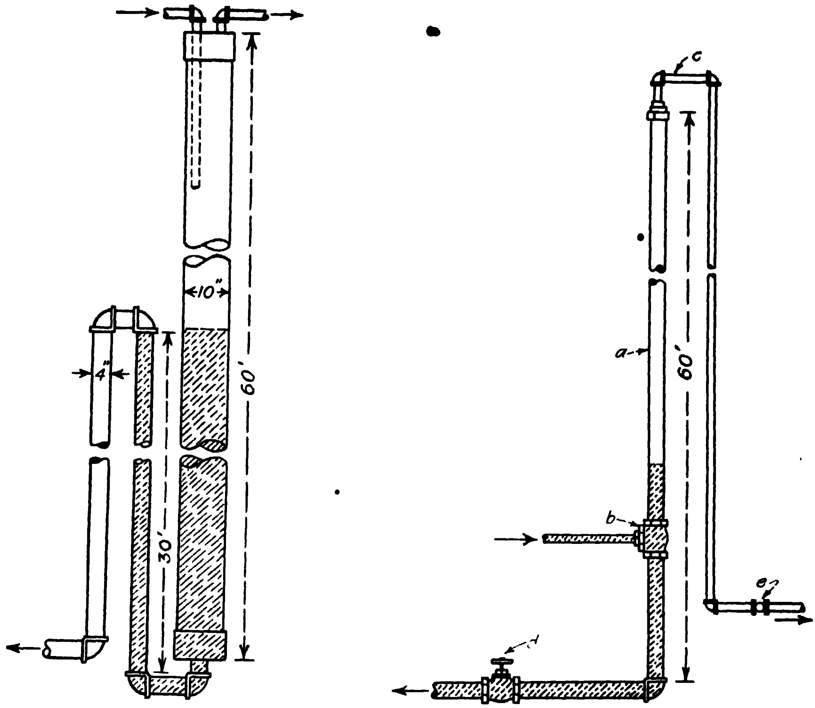
Types of Gas Traps.—All gas traps operate on the principle of passing the oil and gas through a receptacle large enough to reduce the velocity of flow, so that the gas has an opportunity to separate. A reduction of pressure within the trap and the maintenance of a free space above the oil surface will operate to bring about the desired separation. Some traps spread the oil out into a thin film on inclined conical surfaces with the same object in view. Gas rises from the oil and is led off at the top of the trap free from oil. The oil is drained from a point near the bottom of the trap, a definite fluid level above the oil outlet being preserved by a suitable device to maintain the gas seal.

Traps have been designed to meet a variety of conditions. The pressures employed may range from partial vacuum to 50 lb. per square inch or more. Some traps are suitable only for small volumes of gas, others are intended to handle unlimited amounts. Certain traps described in the following pages are also designed to assist in the removal of sand and water.

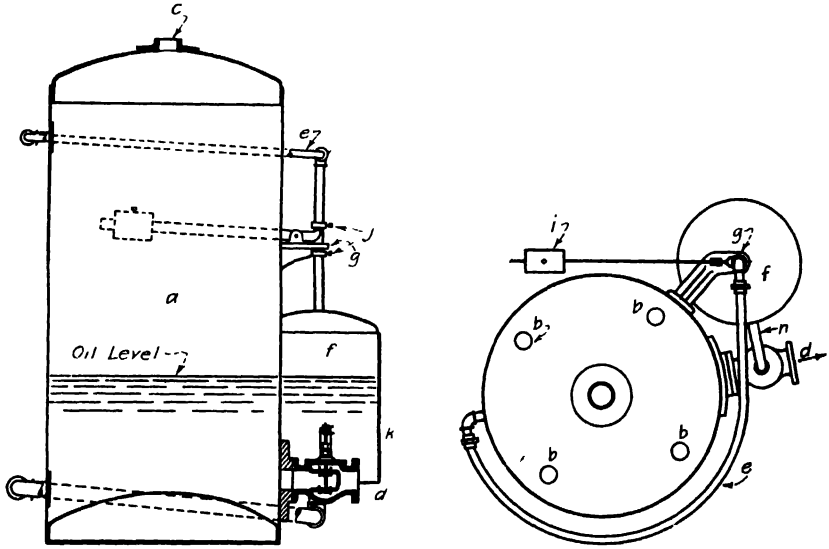
Gas traps may be classified as to form and type into two general groups: vertical cylindrical traps, and horizontal tubular traps. We may also distinguish between traps which control the oil level by valves actuated by floats or other mechanical contrivances, and those which maintain a constant level through the use of a gooseneck or inverted syphon. The latter method of control is characteristic of a group of low-pressure traps.

Vertical Pipe Traps.—A simple type of pipe trap depending upon a gooseneck to preserve the gas seal is illustrated in Fig. 271. It can be made of materials readily available about any oil-producing property, and is effective if the quantities of oil and gas to be handled are small, and if sand is not present in quantity.[1]

A slightly different arrangement of the oil inlet and outlet connections, also illustrated in Fig. 271, increases the utility of this type of trap. In this case, oil enters the vertical pipe *a*, which is 4 in. or more in diameter and 40 or 60 ft. long, at *b*, a few feet above the bottom. This arrangement serves to reduce the velocity, and the surging of the oil in adjusting itself to the changed direction and velocity of flow liberates the gas, which rises to the upper part of the pipe, escaping through pipe *c*. Oil, as well as sand and water, if present, pass downward through pipe *a* and are drained off at the bottom, the flow being carefully regulated by valve *d*. The adjustment of valves *d* and *e*, and the pressure back of the incoming oil, will determine the height to which oil will rise in the trap, and this, in turn, governs the velocity of efflux. The pipe, *a*, is conveniently supported against one side of the derrick, in which case it is not quite vertical. This trap operates satisfactorily even on large high-pressure wells, as long as the production of oil and gas is fairly steady, but is difficult to regulate if the volume and pressure conditions are erratic.



(*After W. R. Hamilton in U. S. B. Mines Tech. Paper 209*).
FIG. 271.—Types of vertical pipe traps.



(*After W. R. Hamilton in U. S. B. Mines Tech. Paper 209*).
FIG. 272.—The "Oilwell" high-pressure trap.
At right, plan view; left, side elevation.

The oil well high-pressure trap,* illustrated in Fig. 272, is of the vertical cylinder, mechanically controlled type.[1] The valve regulating the oil level within the trap is in this case automatically controlled by the weight of oil in a small cylindrical tank, *f*, externally located and mounted at one side of the trap. This small tank is connected at top and bottom directly with the trap by means of a pair of pipes, *e*, bent to

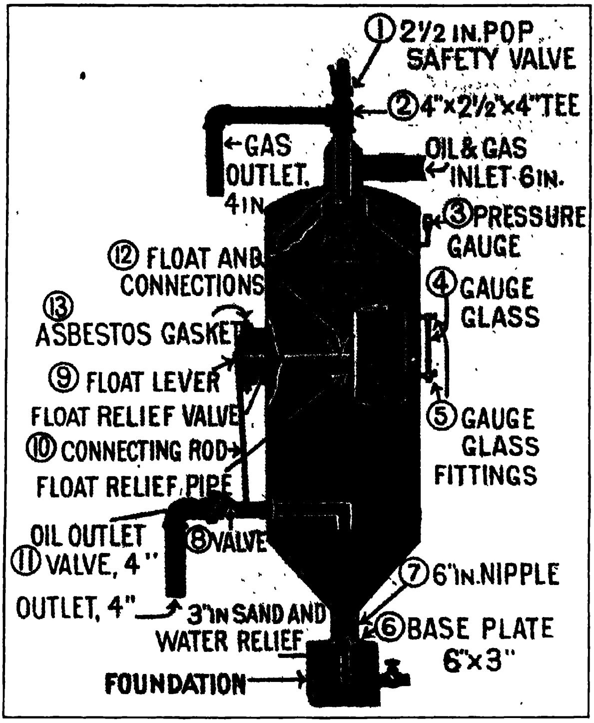


FIG. 273.—Trumble trap.

semi-circular form and extending halfway around the trap before making connection with it. The small tank is supported in a vertical position by a suitable guide or bracket, *g*, attached to the side of the trap in such a way that the small tank is free to move up and down through a distance sufficient to actuate the control valve, *k*, with which it is connected by lever *h*. Vertical movement of the small tank is facilitated by the "spring" in the semi-circular connecting pipes. Such portion of the weight of this auxiliary tank as is not supported by the connecting pipes and valve mechanism is counterbalanced by a weight, *i*, which may be placed at varying distances from the fulcrum on which its supporting lever bears, thus permitting of close adjustment to keep the tank, *f*, in any desired position.

The oil, when admitted to the trap through the top openings, *b*, accumulates in the bottom of the main tank, *a*, and as the fluid level rises, oil will flow through the lower connecting pipe, *e*, and maintain the same fluid level in the small tank, *f*. When sufficient oil has entered *f* to offset the weight of the counterpoise, *i*, the tank bears

* Manufactured by the Oil Well Supply Co., Pittsburgh, Pa.

down on lever *h*, opening valve *k* which controls the flow of oil through the oil outlet, *d*. Flow of oil from the trap will result in a lowering of the oil level in *f* until the counterpoise weight exceeds the weight of the oil. The tank *f* then rises to its original position, closing or partially closing the control valve, *k*. This action is intermittent and is repeated as long as oil continues to enter the trap. If the flow of oil and gas is fairly constant, the mechanism controlling the valve may come into equilibrium, throttling the flow of oil from the trap so that it just keeps pace with the rate at which it enters. Gas leaves the trap through an opening, *c*, in the top.

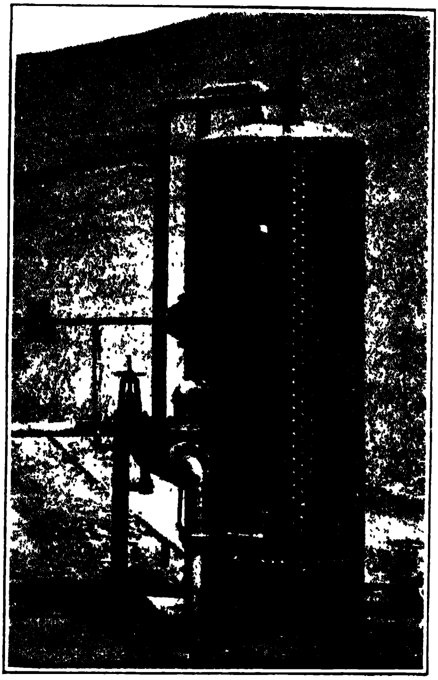


FIG. 274.—The Lorraine trap.

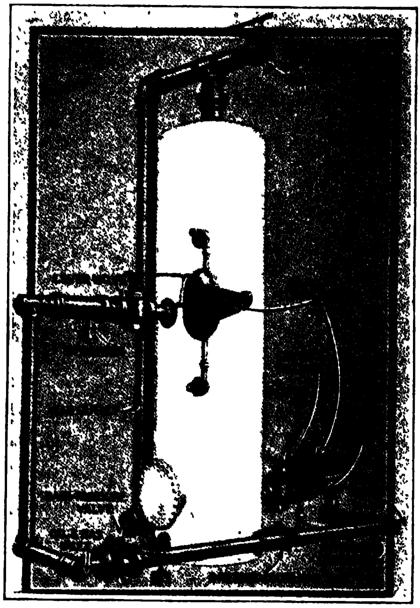


FIG. 275.—Smith oil and gas separator.

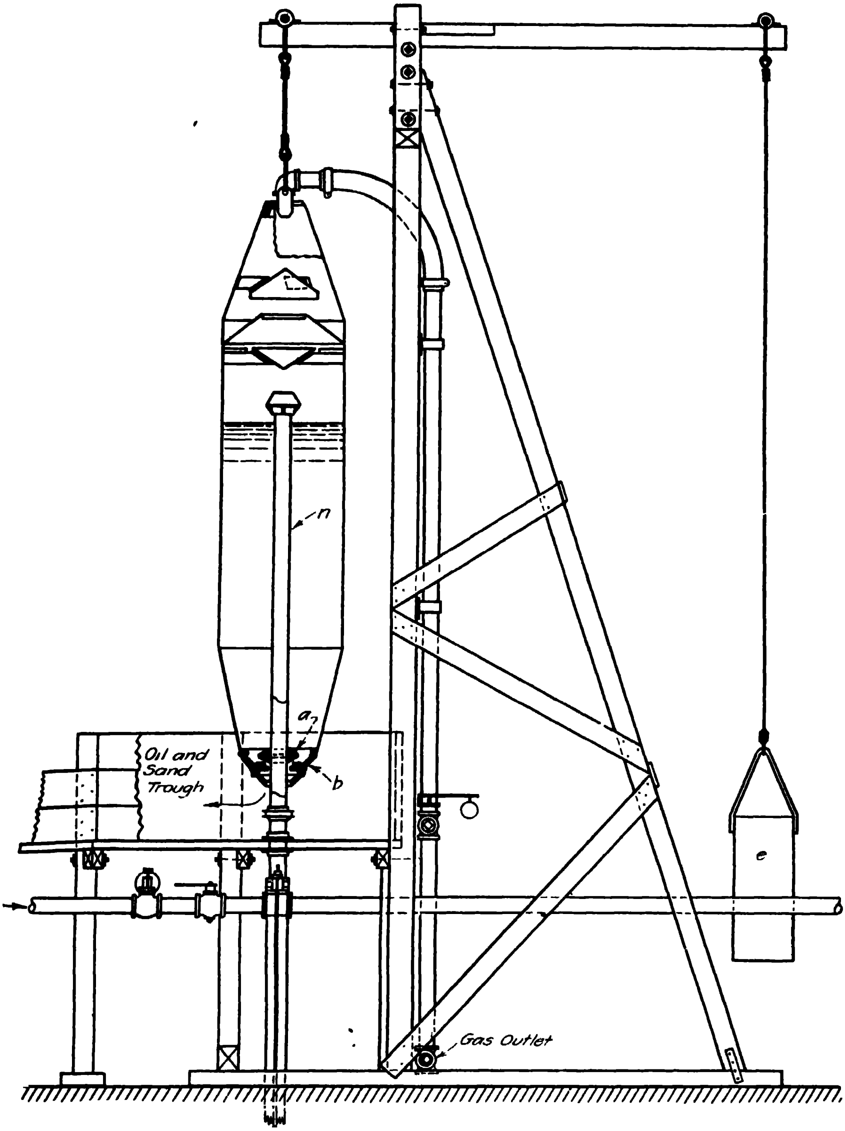
The only attention necessary with this trap is an occasional inspection of the valve stem adjustment. The valve control is independent of pressure variations, and works equally well under all pressures. This trap is well adapted to use with light oils, but is less efficient with heavy viscous oils which are unable to flow rapidly enough through the spring pipe to operate the valve promptly when there is any sudden change in the flow of oil and gas into the trap.

Traps with External Valves Actuated by Internally Placed Floats.—The Trumble trap,* the pioneer trap of this type, is illustrated in Fig. 273. The fluid level is controlled by means of a float, which in this case operates an externally placed valve through a series of connecting levers passing through a stuffing box in the side of the trap. Oil enters the trap at the top, and falls over a series of conical baffles to the bottom of the trap. During the descent, gas is liberated from the oil and flows out through the pipe, 2. Excessive gas pressure within the trap is prevented by blowoff valve 1. Oil flows from the trap through pipe 11, and the oil level within the trap is

* Manufactured by Trumble Gas Trap Co., Los Angeles, Cal.

disclosed by gage glass 4. Sand and water which tend to collect in the conical bottom, may be occasionally drained through outlet 7.

Other well-known traps of this type are the Lorraine trap,* illustrated in Fig. 274, widely used in the fields of southern California, differing from the Trumble trap chiefly



(*After W R Hamilton in U S B. Mines Tech Paper* 209).

FIG. 276.—The McLaughlin trap.

in the type of valve used, and the Smith oil and gas separator† (see Fig. 275), which differs from the Trumble and Lorraine types in that a separate compartment is

* Manufactured by Lorraine Gas and Oil Separator Co., Los Angeles, Cal.

† Manufactured by the Smith Separator Co., Tulsa, Okla.

provided for the float which actuates the valve. The Smith separator is popular in the mid-continent fields.

The McLaughlin trap consists of a cylindrical tank, having a conical top and bottom, which is suspended on the end of a horizontal beam, pivoted on a vertical post, as illustrated in Figs. 276 and 277. The weight of the trap is balanced by a counterpoise, *e*. The axis of the cylindrical tank is vertical, and the entire trap is free to move up or down as the weight of the fluid within it varies.[1] The inlet pipe, *n*, enters the bottom of the trap and is stationary. On the outside of this pipe, near the bottom of the trap, is attached the discharge valve, *a*, consisting merely of an annular ring ground to fit a

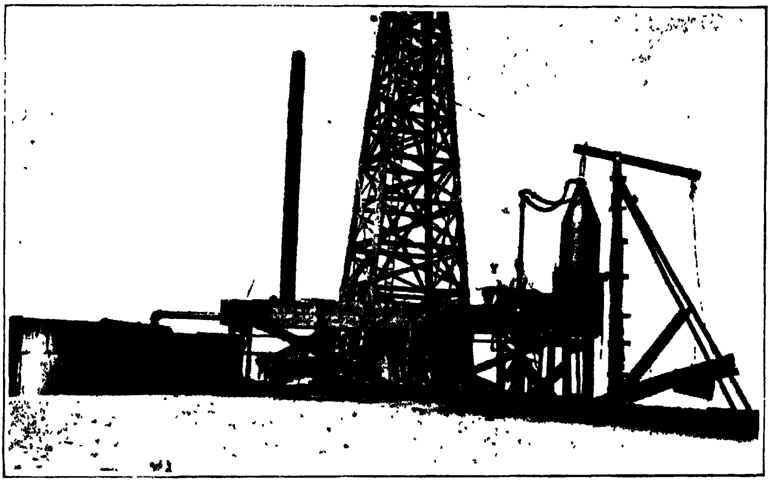


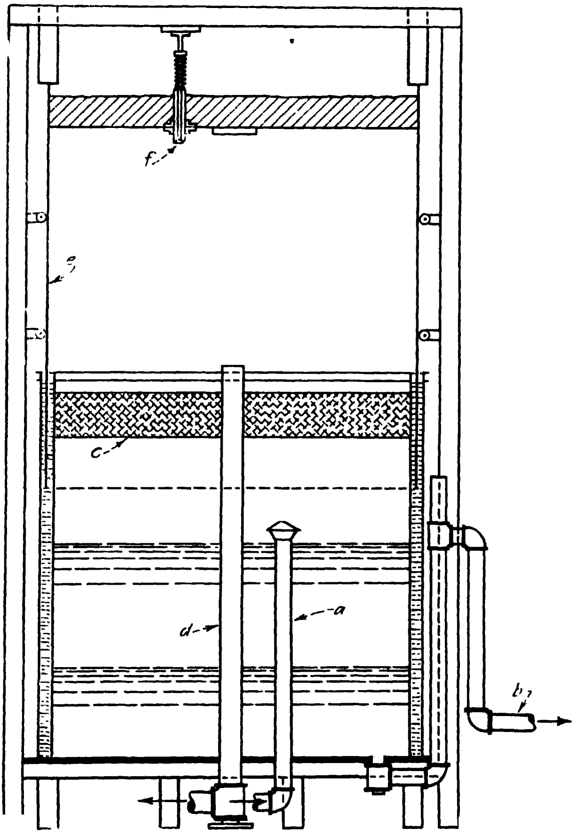
FIG. 277 — The McLaughlin trap with sand separating box and receiving tanks.

seat, *b*, mounted on the lower end of the trap, through which the standpipe, *n*, passes. This valve effectively opens or closes the oil outlet around the vertical standpipe as the trap falls or rises.

Oil and gas, containing, perhaps, water and sand also, flow into the trap through pipe *n*, and are deflected downward by the deflector mounted on its upper end. As long as the trap is empty, the counterweight, *e*, keeps the valve seat, *b*, securely pressed against the valve, *a*. When fluid has accumulated to a sufficient depth to offset the excess weight of the counterpoise, the weight of the oil on the conical trap bottom will cause it to move downward, thus unseating the valve and permitting some of the oil to flow out around the standpipe into a suitably placed trough through which the oil and water flow to storage, and in which the sand is deposited. When the fluid level within the trap has subsided so that the counterpoise again overbalances the weight of the trap and its contents, the trap will rise and partially close the outlet. If the flow of incoming oil is fairly uniform, the contents of the trap and the counterpoise will come into equilibrium, maintaining the valve in such a position that the flow from the trap will just keep pace. Gas is led off through a flexible hose connection at the top, conical baffles being provided to separate any spray that may tend to accompany the gas.

The McLaughlin trap is adapted, with slight modifications, to either high-pressure or low-pressure conditions, or it may be operated under partial vacuum if desired. If there is not too much sand in the oil, the outlet may lead to a pipe of suitable size connecting directly with the gathering system, instead of passing the oil through a sand

trough as illustrated in Fig. 276. In recent installations of the McLaughlin trap, supporting springs have replaced the cumbersome beam and counterbalance. A suitable supporting framework must be provided in this case, and the springs must admit of close adjustment in order that they may be adaptable to variations in the working conditions imposed. As the oil outlet is at the bottom, the McLaughlin trap is admirably adapted to oils which carry sand or water in quantity. The impurities are discharged with the oil and the trap is not encumbered with them. Furthermore, the action of the trap is positive and responsive to sudden changes in quantity of oil, or in volume and pressure of gas.



(*After W. R. Hamilton in U. S. B. Mines Tech. Paper 209*)
FIG. 278.—Scharpenberg low-pressure trap.

The Scharpenberg low-pressure trap is of the vertical cylinder type, in which the fluid level is regulated by a gooseneck or inverted syphon.[1] The trap consists of three vertical steel cylinders, two of which telescope, one over another, while the third serves to provide a water seal for the other two, after the design of the ordinary gas holder (see Fig. 278). The floating tank is sealed at the top so that it is gas-tight. Oil enters through a standpipe, *a*, penetrating the bottom, and is deflected downward by a suitable deflector. The fluid level in the trap is determined by the gas pressure and by the height of a gooseneck on the oil outlet, *b*. The upper end of the gooseneck is open to the atmosphere to prevent syphoning. Gas, in rising from the oil surface to

the top of the trap, passes through a layer of excelsior, *c*, supported within wire screens, the function of which is to separate any oil spray which may accompany the gas; and is drawn off at the bottom through the vertical standpipe, *d*. The floating cylinder, *e*, serves to maintain a constant gas pressure on both the well and the gas delivery line, rising and falling on the water seal as the gas volume varies. If the trap is drained of gas, the upper cylinder descends and rests on the standpipe, *d*, thus closing the gas outlet and preventing the formation of vacuum which might draw air through the oil and water seals. If gas is produced in excess of the capacity of the gas main, the relief valve, *f*, is opened as the tank reaches the upper limit of its travel, thus preventing excess gas pressure from destroying the oil and water seals.

Some installations of Scharpenberg traps have been equipped with cylinders about 10 ft. in diameter and 10 ft. high. They are adapted to pressures ranging from a few ounces to 1 lb. per square inch, gage pressure.

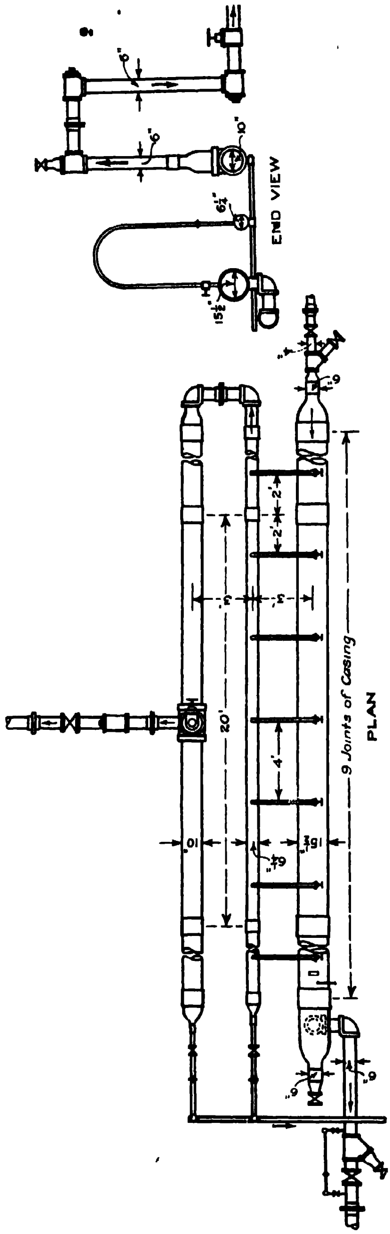


FIG. 279.—The Starke trap.
(*After W. R. Hamilton in U. S. B. Mines Tech. Paper 209*).

The Starke trap will serve as a single example of the horizontal tubular type of trap (see Figs. 279 and 280). It can be assembled from pipe, casing and fittings ordinarily available in the field and, though used chiefly on high-pressure flowing wells, can be regulated to operate satisfactorily under any desired pressure and volume of through-put.[1] It consists of two or three lengths of pipe, 120 to 160 ft. in length, laid horizontally and carefully leveled. One of these pipes is of large size, commonly 12½ or 15½ in. in diameter. This is the separating chamber, never more than half filled with oil, in which the fluid is brought to comparative rest and the gas permitted to separate. The gas accumulating in the upper half of this pipe escapes through inverted

U-shaped risers into the gas-collecting pipe, which is of smaller diameter, about 6¼ in. Oil enters at one end of the larger pipe and is drawn off at the other, the valve controlling the flow of oil from the trap being carefully regulated to pass the same quantity of oil that is admitted. A gage glass, showing the level of oil in the cross-section of the pipe, aids in making this adjustment. Often a third line of intermediate sized pipe, about 10 in. in diameter, is connected with the 6¼-in. line to serve as a gas reservoir or receiver, and to equalize the pressures within the trap and gas transmission main. While this trap is not intended for use with oils con-

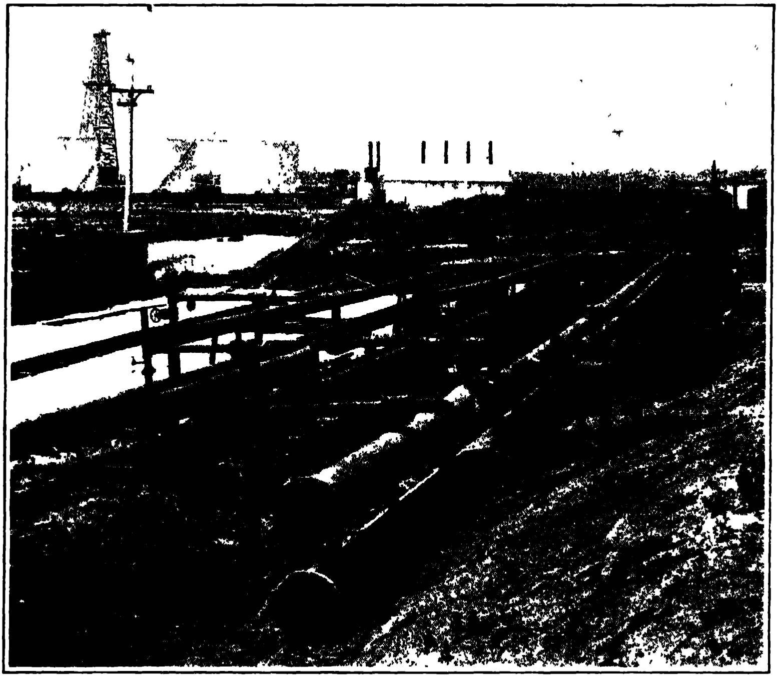


FIG. 280.—Improved form of Starke trap with Lorraine trap.

taining large percentages of sand, a short length of pipe, equipped with a valve, placed below the level of the main separating pipe and connecting with it near the oil outlet, may act as a sand trap. Occasional opening of the valve flushes out the accumulated sand.

Recent development in the application of the Starke trap has simplified the early designs somewhat. In a trap of small or moderate capacity, two pipes are adequate and the smaller gas-collecting pipe is placed directly above the oil-separating pipe instead of at one side. Straight risers of shorter length are substituted for the U-shaped risers. Instead of relying on screwed fittings for connecting the various parts, they may preferably be welded together with the aid of the oxyacetylene torch.

Influence of Trap Pressure on Oil and Gas Production.—Gas traps may be operated at pressures varying from a partial vacuum to the maximum pressures available under working conditions. It is found that the pressure maintained on the trap, that is, the gas pressure within it, has a pronounced effect upon the amount and character of the oil and gas

produced, and upon the amount of sand and condition of the water present as impurities.

Many operators believe that back-pressure maintained on a well by connecting it with a trap operating under high pressure will result in curtailed production of oil. This seems reasonable as it is the differential between the well pressure and the pressure within the producing oil stratum that causes flow of oil into the well. However, in fields characterized by highly porous, loosely cemented sands, wells operated under considerable back-pressure do not produce as much sand as do wells operating under atmospheric pressure. Again, flowing wells which produce "by-heads" will often flow with greater regularity when the product of the well is passed through a trap maintained under moderate pressure. The gas wasted in "blowing" after each discharge of oil will then be put to more useful service in lifting a greater volume of oil. The absence of mechanical difficulties due to the decreased production of sand, and better utilization of the lifting power of the gas, will offset in many cases the loss in oil production which the increased pressure might be expected to bring about. The net result of these opposing factors may actually be an increase in production when the higher trap pressures are maintained. If a pumping well is not troubled with sand, it is undoubtedly to the advantage of the producer, as far as oil production is concerned, to operate under as low a pressure as possible. However, if the pressure of the gas separated at the trap is important, as in cases where the gas must be transmitted over a considerable distance, it may be poor economy to sacrifice potential gas pressure to gain an increased volume of oil. Occasionally, if both the additional quantity of oil and the gas pressure are important items, it will be profitable to insert a gas pump between the trap and the gas transmission main, the pump serving the double function of applying suction or vacuum on the trap, and pressure within the gas transmission main.

The pressure maintained within a trap also has a marked influence on the components of the gas produced. If the oil contains low-boiling constituents, vacuum or low-pressure conditions within the trap increase vaporization, making the gas richer in these low-boiling fractions, with consequent loss in volume and Baumé gravity of the oil. High pressures within the trap have the opposite effect, tending to prevent the escape of these light components of the oil, and even bringing about condensation of certain vapors from the gas, thus adding to the volume and Baumé gravity of the oil. Increasing the pressure on a trap from slightly above atmospheric pressure to 50-lb. gage has been responsible for an increase in Baumé gravity of the oil produced, from 27° to 30°, with a definite increase of about 4 per cent in the volume of oil. In localities where oil is sold on a sliding scale based on the Baumé gravity, such an increase is a decided gain to the producer; but in cases where the price is not condi-

tioned by density, it may be to the advantage of the producer to operate with traps under reduced pressure, volatilizing as large an amount of these low-boiling constituents as possible, later recovering them as gasoline by treating the gas in a compression or absorption plant. The operator must weigh these opposing factors, determining in each case which method of operation will produce the greater revenue.

Another advantage of high trap pressures is found in the case of wells which produce water in emulsified form. High-pressure production apparently results in the formation of less emulsion in such cases. Producers have found it advantageous in the case of high-pressure flowing wells, where reducing nipples have been used in the lead lines at the casing heads, to remove these and place them after the trap. Removal of the gas before the oil and water flow through the restricted orifice will ordinarily result in the formation of less emulsion.

Separation of Water from Petroleum: Dehydrating

The dehydration of petroleum is a problem that becomes important sooner or later in the life of every oil-producing property. While water "troubles" develop early in the life of many fields, almost from the time of the earliest development in some cases, the problem of dehydrating in its broader aspects is characteristic of the later period of declining productivity; when the gas pressure and oil supply are waning, when casings have had time to corrode away or when defective water shut-offs have had time to display their influence. Water present in the oil for these causes is, for the most part, extraneous water that has found its way into the oil-producing stratum from water-saturated beds, usually above—though occasionally below—the oil-producing horizon. Water incursion from these sources is generally remediable by making proper repairs to the well, or replacement of its equipment.

Water in many cases, however, is present in the oil-producing stratum through natural causes. In flat or low-dipping formations, oil of low Baumé gravity sometimes does not possess enough gravity advantage to bring about a complete separation of the two fluids, and they will be found closely associated in the same porous stratum. In other cases, the upper portion of a thick porous bed, horizontally disposed or nearly so, may contain petroleum, while the lower portion may be water-logged. There may be no impervious parting or plane of separation between the two fluids, so that wells drilled into the stratum will produce a mixture of water and oil. The encroachment of edge water is also responsible for much of the water pumped with the oil from wells. Water rises from the edges of the pool and replaces the oil as it is removed. Eventually all oil wells, if pumped long enough, will produce water only,

though for a time they may produce a mixture of the two fluids with a continually increasing percentage of water. In such cases, where water is a product of the same formation as the oil, there is no alternative, if the oil is to be produced, but to remove some of the water with it.

The percentage of water in the gross fluid production of a group of wells will vary with the local conditions pertaining in each case. Often it is negligible, perhaps only 1 or 2 per cent, or even less; in some cases it has been found profitable to operate wells the production of which averages upwards of 90 per cent water.

A simple test that may be readily applied in the field to identify the presence of water in oil consists in allowing a few drops of the oil to flow down a clean glass surface, forming a thin film. If water is absent, or present only in small amount, the oil will appear as a clear, amber-colored film with sharp edges, while if the oil contains water, the film will not be uniform in appearance and the edges will not be sharply defined.

Condition of Water in Petroleum.—Water may be present in association with oil either in the "free" state, or "emulsified." The former term is relative and has no exact significance, being applied to the water which separates from the oil by mere gravity settling, assisted by moderate application of heat to reduce the viscosity of the oil. When emulsified, the oil and water are so intimately associated that the influence of gravity becomes negligible, even at temperatures considerably above normal; the mixture assumes colloidal properties and the water remains in permanent or semi-permanent suspension.

The stability of oil-water emulsions is quite variable. Water will settle to some extent from semi-permanent emulsions on prolonged standing, while others of more permanent type show no tendency to separate even though left undisturbed for years. The more stable emulsions are often a source of great trouble and expense to the producer in preparing his oil for market.

Some investigators claim, and have offered experimental data indicating that the amount of water present in "true" emulsion is remarkably constant, and averages[7] about 66 per cent. Other investigators have stated that the percentage of water may vary from traces up to 75 per cent or more, and that the majority of emulsions contain about 25 per cent. Since emulsions are miscible in clean oil in all proportions, it is probable that some confusion in terminology has arisen.

Emulsions may have physical characteristics quite dissimilar from the oil of which they are partly composed. Their specific gravity is, of course, higher because of the water present. The color is variable, commonly dark reddish-brown, though any shade from yellowish-brown to greenish, gray or nearly black, may be found. Perhaps the most striking characteristic is the high viscosity. All gradations in consistency from that of a thick syrup to a semi-solid are common.

Microscopic studies have shown that in permanently emulsified oil the water is present as minute globules ranging in diameter from .004 to .025 mm. Small bubbles of air or gas are usually also to be observed in the mixture. Each globule of water appears to be encased in a film of oil, the average distance between water globules in permanent emulsions being less than one-half their diameter. The size of the water globules apparently does not have as much significance in determining the character of the emulsion as the distance between globules. In temporarily emulsified oil-water mixtures the water globules are from 10 to 20 diameters apart.[7] At greater distances the water globules settle freely, even though of small size. It is thus evident that no sharp line of demarcation may be drawn between "free" water and "emulsified" water.

Chemical analysis of the water present in petroleum emulsions discloses the fact that dissolved salts are almost universally present, occasionally to the extent of 10 per cent or more. Whether or not this is an essential condition to the formation of emulsions has not been determined, though it can be demonstrated experimentally that while pure water does not readily emulsify with petroleum, the addition of various salts to the water—particularly chlorides and sulphides—will radically change its emulsifying properties. It seems probable that the addition of such substances results in a reduction of the surface tension of the water, so that the two fluids tend to mix more readily. The water is often alkaline, though in some instances it is weakly acid.

In speculating on the reasons for the formation of petroleum emulsions pumped from wells, some investigators have claimed that either air, gas, water vapor or voids[7] (or "a break in the continuity of the fluid") are essential to the formation of emulsions; or at any rate, that the formation of emulsions is much facilitated by their presence. This contention is substantiated by experimental proof, and it is suggested that the formation of emulsions may be largely prevented by proper attention to the mechanical details of pumping and screening. Conditions which would result in air or gas being drawn into the well tubing with the oil should be avoided as far as possible. The fluid level maintained in the well should be above the perforated tubing and the fluid should not be pumped from the well faster than it flows from the sand. If gas is unavoidably present with the oil, and water is also present, it should not be passed through restricted openings, such as reducing nipples, air-lift nozzles, or throttled by partially closed valves on the gas traps or lead lines.

The water drops present in petroleum emulsion are usually negatively charged, some authorities[9] believing that the absorbed ionic charge on the dispersed fluid is in part responsible for the formation of emulsions, through reduction of surface tension. Whether or not this is true is

difficult to prove, but there is no doubt but that the electric charge contributes to the stability of emulsions.

Recent investigations have shown that a stable emulsion between two immiscible fluids is possible only in the presence of a third substance, commonly called the emulsifying "agent," which collects on the fluid surfaces between the two liquids, forming a coherent film strong enough to resist the interfacial tension tending to cause coalescence.[5] An emulsifying agent may be either a finely divided, colloidal solid, or it may be a substance soluble in one or the other of the two liquids, but not in both. The soluble substances alter the relative surface tensions of the two liquids, which operates to promote emulsification.

Emulsions may consist either of minute globules of water in oil, or of small particles of oil in water. If the emulsifying agent is soluble in water or is more readily wet by water, the aqueous phase will be external; but if soluble in oil or more readily wet by oil, the oil phase will be external. As water is always present in the dispersed phase in oil field emulsions, it is probable that the emulsifying agent is an oil-soluble substance; and the evidence produced by several investigators points to certain asphalt-like bodies, dissolved in the oil, as chiefly responsible for most petroleum emulsions. Sherrick[9] states that it is possible to prepare an emulsion of salt solution with pure paraffin oil by the addition of only 0.5 per cent of asphalt. Dodd[5] has found that the amount of asphalt in solution largely determines the readiness with which the oil emulsifies.

Solid, earthy or crystalline impurities are often present in oil field emulsions, and may assist in emulsification, though they are not an essential constituent as some investigators have assumed. It should be noted, however, that large percentages of suspended solids tend toward permanence of emulsification. Emulsions have been formed by agitating gasoline in a mixture of water and finely divided clay, in which water constituted the external phase, while an oil-wet clay will form an emulsion in which oil is the external phase.*

Various methods have been proposed for dehydrating these oil-water mixtures, some of which have been put to practical use on a large scale. It is apparent that, in order to dehydrate emulsion, it is necessary to break or destroy the oil films which enclose and separate the small water globules, so that they may coalesce and form larger globules on which gravity may have a greater influence in bringing about settling. The force which opposes this agglomeration of water particles can be resolved into terms of differential surface tension, though it has been suggested by Sherrick[9] that as the water drops are electrically charged, their reluctance to coalesce may be the result of repulsion of like charges.

* JOHNSON H. A., An investigation of petroleum emulsions, *Thesis* performed under the direction of the author, University of California, 1923.

DEHYDRATING METHODS

Of the various dehydrating methods that have been proposed and applied on a working scale, the most widely used up to the present time are those which depend upon the action of heat, applied either directly to the oil over a furnace, or indirectly through the use of steam, hot water or hot compressed air or gas. Such methods are successful except in the case of exceptionally stable emulsions. Electrical methods which subject the oil-water mixture to either high-potential alternating current or a direct current of moderate intensity are comparatively new, but have already attained wide popularity and give promise of becoming the universal dehydrating method of the future. They are successful with the most refractory emulsions. Other methods that have been suggested and applied to some extent on a limited scale include filtration methods, centrifugal methods, processes making use of chemical reagents and a very recent method based on the effect of differential capillarity.

Methods Depending upon the Action of Heat.—If water is present in the "free" condition or only partially emulsified, separation can usually be readily effected by heating to from 80 to 200°F. At such temperatures the viscosity of the oil is much reduced and the water settles under the influence of gravity.

Hot Water Treatment.—The usual method of applying the heat when moderate heating is effective consists in heating a relatively large volume of water in a tank by means of a steam coil placed in the bottom. The oil and water mixture is discharged from a pipe coil or "spider" giving uniform distribution at points near the bottom, slightly above the steam coil, and floats in small globules to the water surface. During the time that the oil is rising in the treatment tank, it is heated by the surrounding water, causing a reduction in its viscosity. The water globules detach themselves from the oil, aided by the greater relative expansion of the oil under the influence of heat, and remain behind as an addition to the water layer in the tank. The oil, cleaned of its water content, accumulates in a layer floating upon the hot water surface. Suitably placed drains with valve control accomplish the removal of the oil and water, together with any gas which may be formed, so that the hydrostatic head, position of the water surface and temperature conditions are maintained fairly constant. It is important in the design of such a tank that the steam coil does not come into direct contact with the oil, otherwise it will gradually become coated with a deposit of solid hydrocarbon, thus reducing its efficiency as a heating device. The water layer in the tank tends to accumulate salt from the brine which accompanies the oil. Some operators report improved results through keeping the water in the tank fairly fresh, adding water from an outside source from time to time to displace the accumulated brine.

In one installation operating on the hot water method of indirect heat application, the treatment tank is of cylindrical form, 8 ft. in diameter and 20 ft. high. The oil is admitted to the tank through 1/8-in. holes bored in a series of distributing pipes, so arranged as to give a fairly uniform distribution of oil across the entire cross-section. The steam coil is made up of about 500 ft. of 2-in. pipe and is submerged in 10 ft. of water maintained at a temperature of 150 to 200°F. The capacity of such a dehydrating unit will be variable, depending upon the characteristics of the oil under treatment and the condition of the water in it, but should be at least 500

bbl. per day, even under unfavorable circumstances. The method is continuous, and once the valve controls have been properly adjusted, the equipment requires little attention.

Dehydrating with Hot Compressed Air.[8]—Another method of indirect heating, which admits of attaining a somewhat higher temperature than is possible with hot water treatment, is that patented by Milliff and used by the Associated Pipe Line Company at its Port Costa, Cal., terminal in dehydrating emulsion formed in operating the rifled pipe line. Heated compressed air is the heating agent in this process. The treatment tank is cylindrical in form, 8 ft. in diameter and 20 ft. high, and is equipped with 3-in. piping perforated at intervals with $\frac{1}{16}$-in. holes through which the heated air enters. This piping is distributed over the bottom of the tank to give suitable distribution of the air to the oil, which nearly fills the tank. The air must be under sufficient pressure to offset the head of oil maintained in the tank, and is heated before injection into the oil to a temperature of about 1,000°F. by a system of piping over an oil-fired furnace.

The oil is, in this process, heated to a temperature sufficient to vaporize some of the water present in the oil. The generation of steam bursts the water globules, freeing from the enclosing films such portion of the water as is not vaporized, so that even the more stable emulsions are broken down. The steam and compressed air, together with a certain amount of vaporized oil which is inevitably formed at the temperatures prevailing, escape at the top of the tank. Water accumulates in the bottom of the treatment tank and is occasionally drained off. Dehydrated oil is removed by a pipe so placed as to skim the surface fluid.

Large volumes of emulsion have been successfully treated by this process, the resulting product containing less than 1 per cent of water. The operating cost, however, is high in comparison with other methods, and the losses in vaporized oil may be considerable, particularly with light oils, unless some method of condensing the oil vapors is also employed.

Other Evaporation Methods.—Certain dehydrating methods designed for handling even the most refractory emulsions make use of the evaporative principle, actually vaporizing all of the water present by heating to a temperature well above the boiling point of water. This is accomplished by direct heating of the oil over a suitable furnace. The temperature necessary to bring about vaporization of the water results also in evaporation of the lower boiling constituents of the oil. Consequently, unless these lighter and more valuable fractions are to be sacrificed, the water and hydrocarbon vapors must be passed through a condenser and recovered. Such a process is seen to be actually a "topping" process, and its technology would, in a strict sense, fall within the province of the refinery engineer rather than that of the petroleum production engineer. However, inasmuch as such treatment is sometimes applied primarily for the purpose of dehydrating, and since the plant by which it is accomplished must ordinarily be located in the oil field and operated by the producer, it seems appropriate at this point to describe briefly one such process.

The dehydrating plant of the Nevada Petroleum Company, located in the Coalinga field, California, was designed by S. J. Hardison and is described by him in a paper read before the American Institute of Mining Engineers.[6] The petroleum produced on the Nevada Petroleum Company's property consists of a mixture of oil with "free" water and emulsion, and after considerable experimentation with various methods of heating, a method involving heating to from 230 to 250°F. was adopted.

The heat is applied by pumping the oil through 54 joints (1,080 ft.) of 3-in. pipe, connected by return bends and mounted in a brick furnace of special design, heated by fuel oil (see Fig. 281). The pipe is placed in a large chamber at the base of the stack, but is not subjected to direct contact with flame. Heated oil, after passing

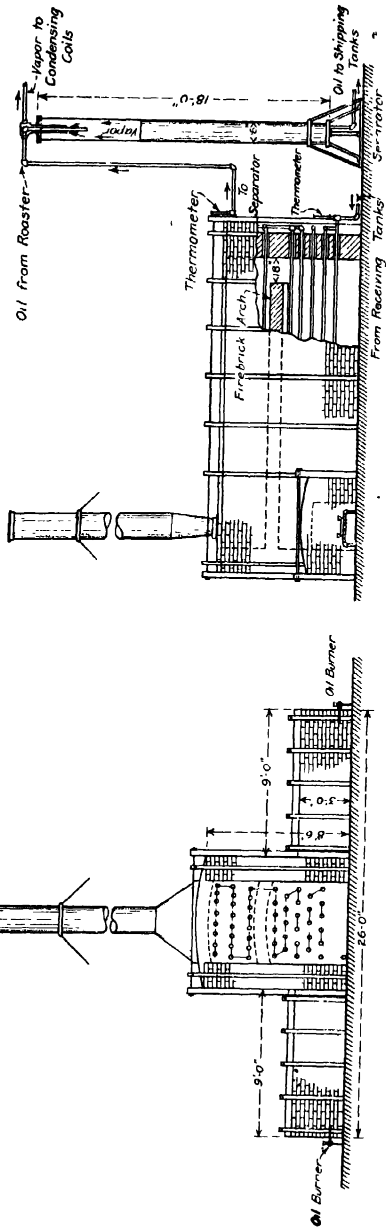


FIG. 281.—Dehydrating plant of the Nevada Petroleum Co., Coalinga Field, Cal. (After S J. Hardison in *Trans. Am Inst. Mining Engrs.*)

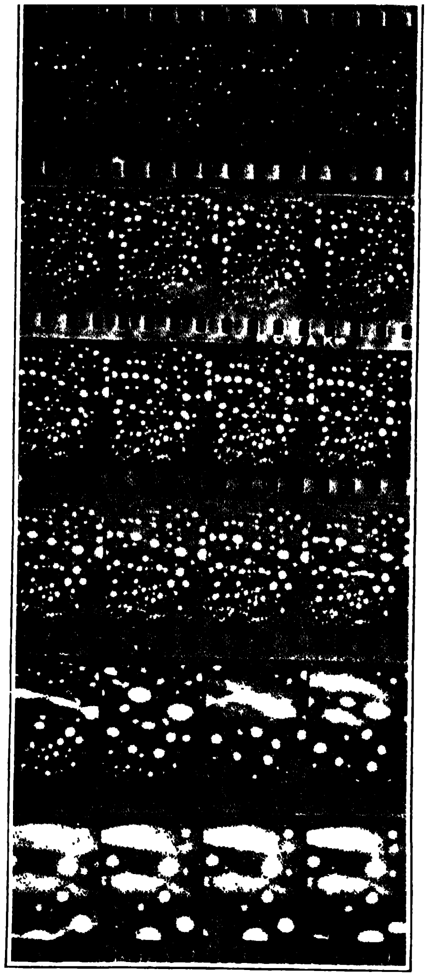
through the furnace, enters a vertical cylindrical receiver, the function of which is to separate oil and water vapors from the heated oil. These vapors escape at the top of the receiver, are passed through a condenser and the hydrocarbon condensate is separated from the condensed water. Heated oil, still containing much of its original water, but now entirely in the "free" condition, is discharged from the bottom of the separator into storage tanks where the water settles out under the influence of gravity, and is periodically drained off.

The oil before treatment has a Baumé gravity of 14.8° and contains 11.6 per cent of water and suspended solids. After treatment, its gravity is increased to 15.5°Bé. and it contains only 1 per cent of impurity. The condensed "tops" have a Baumé gravity of 37.2° and are put back into the crude after the water has been separated.

Operating costs for this plant aggregated only about 1.7 cts. per barrel, but the figures were assembled at a time when oil prices were very low (about 40 cts. per barrel), and the stated cost does not include any capital charges or overhead expense. The plant has been recently supplanted by electrical dehydrators, chiefly on account of increased oil prices.

High Cost of Heat-treatment Dehydrating Methods.—Heating methods, while simple in operation and in the equipment required, and while highly efficient except in the case of the more stable emulsions, are uneconomical from the standpoint of fuel consumption and evaporation losses. This is particularly true in localities where, and at such times as, oil prices are high. Though it may be argued in many cases that heat used for this purpose is exhaust steam from some steam plant used primarily for another purpose, it is generally true that the plant concerned has to operate less efficiently than it otherwise might, because of the steam furnished. In some cases where high temperatures are required,

oil or gas must be burned to furnish the necessary heat, occasionally to the extent of 25 bbl. of fuel oil per 1,000 bbl. of oil treated. Furthermore, the plant used in heat treatment of oils is always short-lived and maintenance costs are usually high. Salts present in the water separated from the oil are particularly detrimental to the metal



(*Courtesy of Petroleum Rectifying Co. of Calif.*)

FIG. 282.—Photo-micrographs of oil-water emulsion under the influence of high voltage alternating current.

The illustration consists of six strips of motion picture film, taken at the rate of four per second and magnified fifty times. Each strip contains four individual photographs.

heating surfaces and tank walls, with which it must come into contact. Where flame is employed directly on heating surfaces, these salts, together with solid hydrocarbon residues, are deposited as a thick adherent scale, often resulting in serious overheating and rupture of the metal surfaces. Costs with these methods have in recent years seldom been less than 5 cts. per barrel, even with cheap fuel, and costs as high as 15 or even 20 cts. per barrel are not uncommon. Still more serious are the evapor-

ation losses, which often exceed 5 per cent. The value of the oil so lost should also be chargeable against the method employed. It is largely because of the fact that it can be operated more economically, particularly when dealing with emulsions, that the electrical dehydrating method has been so generally adopted in recent years.

Electrical Dehydration of Petroleum.—When an oil-water emulsion is subjected to a high-potential alternating electric current, it is found that the small water globules, under the influence of the electrostatic forces generated, tend to coalesce, forming larger masses which may be readily removed by gravity settling. Microscopic studies of emulsions under the influence of the alternating current show that the water globules tend to form chains along the electrostatic lines of force connecting the charged electrodes (see Fig. 282). Apparently when such a chain forms, the greater conductivity of the salt water—in comparison with the non-conducting oil films separating the water globules—causes the latter to be punctured by an electrical discharge. The entire chain of water globules then forms one comparatively large drop, which readily settles under the influence of gravity. Eddy suggests[2] that the water drops may serve as a multitude of series condensers rather than as conducting paths, the minute water particles being the electrodes or poles of the condensers, while the separating oils act as the dielectric which is ruptured by the high voltage.

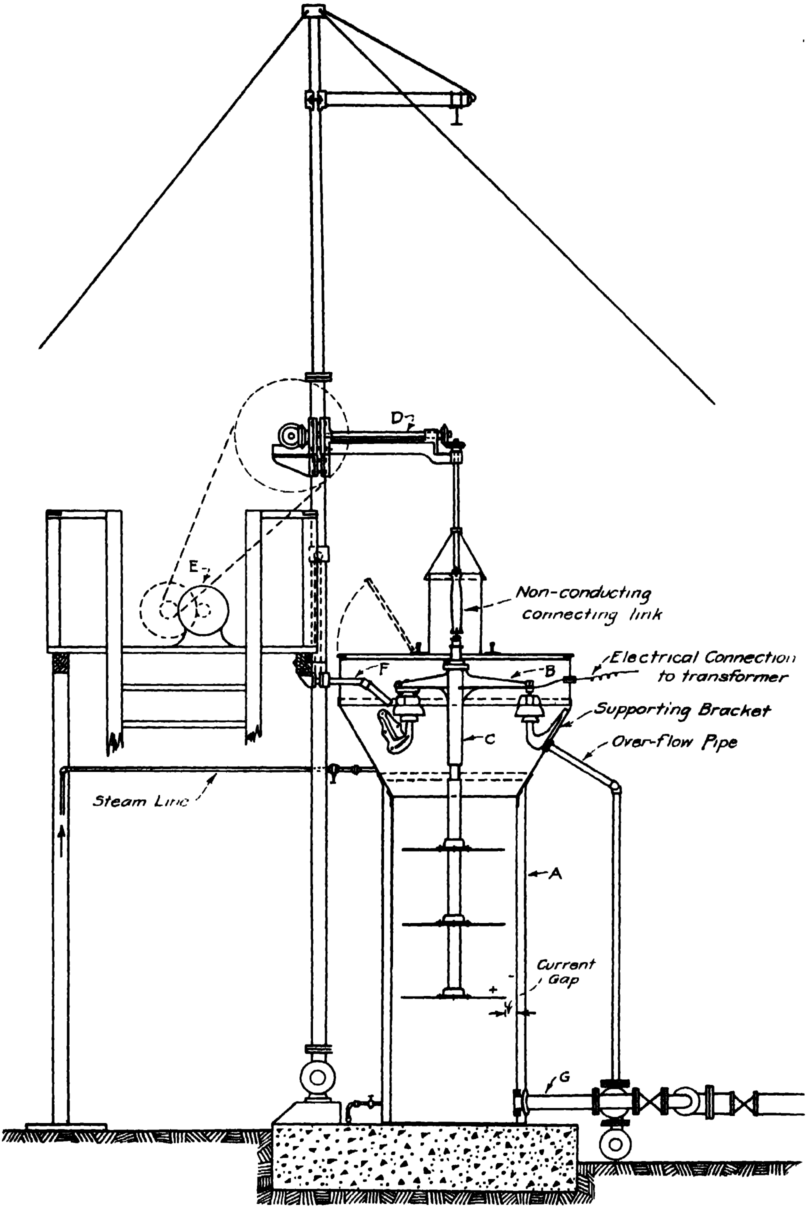
The original patents governing the use of this process in the United States were granted to Cottrell, Speed and Wright in 1911 (U. S. Patents 987, 114-5-6-7) and the process is generally known as the Cottrell process. Patent rights have been assigned to the Petroleum Rectifying Company of California,* which company, after much litigation, has only recently established the validity of its claim to exclusive control of the high-potential alternating current method. The company is prepared to install electrical dehydrating equipment at cost plus 10 per cent, to be subsequently operated on a royalty basis of a flat charge varying from ½ to 2 cts. per barrel of dry oil depending upon the scale of operations.

Practical development of the original Cottrell apparatus has resulted in many modifications of design, particularly in the form of the electrodes and the method of control. The latest design, and one which is regarded as fairly well standardized, is illustrated in Figs. 283 and 284. The unit consists of a double-walled, vertical, cylindrical treatment tank, *A*, 3 ft. in diameter and 8 ft. high, which supports a metal spider, *B*, and is provided with an inverted conical top covered with two semi-circular hinged lids, normally left open for inspection of the oil level in the tank. The spider provides a thrust bearing for a vertical shaft, *C*, which may be caused to revolve by a beveled gear attached to its upper end, the gear meshing with a pinion on a horizontal line shaft, *D*, driven by an electric motor, *E*. Attached to the vertical shaft, *C*, below the bearing and spaced at equal intervals apart, are from 3 to 5 horizontal discs made of heavy sheet steel and of a diameter such as will leave a suitable current-gap between the edges of the discs and the inner walls of the tank. The tank is maintained almost full of oil, which circulates through it at a uniform rate, entering through pipe *F* near the top, and leaving by pipe *G*, at the bottom.

The revolving shaft, to which the discs are attached, is made one electrode and the grounded shell of the tank the other of an electric circuit which carries a voltage of from 5,000, to 13,000 (usually about 11,000) which is sufficient to establish a strong electrostatic field between the edges of the discs and the walls of the tank, and to permit a discharge across the gap when the chains of water globules are formed.

The revolving discs serve to keep the fluid in the tank agitated, thus assisting in bringing all water particles under the influence of the current. Rotation of the central electrode also accomplishes a continual interruption in the electrostatic field, preventing short circuiting of the electrodes through layers of water which might form if both

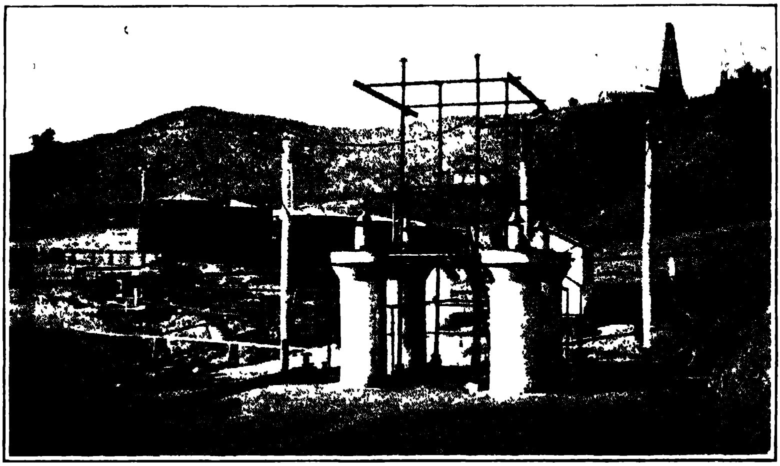
* San Francisco and Los Angeles, Cal.



(*Manufactured by Petroleum Rectifying Co., San Francisco and Los Angeles, Cal.*)

Fig. 283. – Petroleum rectifying company's electrical dehydrating apparatus.

electrodes were stationary. As the oil flows down through the treater, it must pass successively through each annular space between the edges of the discs and the cylindrical inner walls of the tank. The number of discs and the current-gap are variable factors which are determined experimentally for different types of emulsion. The discs are usually either 3 or 5 in number, of No. 12-gage sheet steel, and the current-gap varies between 2 and 6 in. Recent experiments with saw-toothed edges cut on the discs have shown no particular superiority over smooth-edged discs.



(*Courtesy of Petroleum Rectifying Co of California*).

FIG. 284 - Battery of four electrical dehydrators.

The oil in the treater is heated to a temperature of from 125 to 180°F. (average about 135° with California heavy crude) by a steam coil placed in the bottom of the treater below the revolving electrodes. The purpose of this is merely to reduce the viscosity of the oil so that the necessary rearrangement of the water globules may more readily take place. Occasionally the oil must be heated before entering the treater. The necessity for heating the oil has been one of the chief sources of difficulty in the operation of this process—the oil being heated in many cases above its flashpoint, is occasionally ignited by arcing across the electrodes at the oil surface. Until recently most treaters have been equipped with covers which could be closed in case of fire and with a steam coil located just over the oil surface, from which live steam might be injected into the space under the cover in case of necessity. The melting of fusible plugs and connections automatically closes the covers and liberates the steam when a fire occurs. The recent development of an improved form of airtight, closed treater promises to remove the necessity for these devices.

Oil and water leaving the treater, flow to a settling tank of ordinary cylindrical form, in which the water settles under the influence of gravity. It is usually necessary also to equip the settling tank with steam coils so that the viscosity of the oil may be kept low while the settling process is in progress. Water is occasionally drained from the bottom of the settling tank by a suitably placed bleeder, while oil is skimmed from the fluid surface with a swing pipe.

Units of the type described above are arranged in groups of 2, 4, 6 or 8. One California plant, believed to be the largest installation yet made, contains 9 six-unit groups, or 54 treaters in all. One motor will be sufficient to rotate the electrodes of as many as 8 treaters and one 300-bbl. settling tank will be sufficient to receive the

flow from them. The piping, valve and power control is much simplified by this group arrangement. The capacity of a single treater of the proportions given above will vary from 300 to 1,600 bbl. per day, depending upon the character of the oil and the condition and amount of water present. The percentage of water permissible in the treated oil will also determine the capacity to some extent, the effectiveness of the current being largely dependent upon the rate of flow past the electrodes. While 2 or 3 per cent of water is usually permissible in commercial petroleum, electric dehydration will often leave less than 1 per cent of water in the oil, occasionally only .1 per cent. The power consumption ranges between 5 and 75 watt-hr. per barrel of cleaned oil. A 2-hp. motor is sufficient to revolve the electrodes of a six-treater unit. The process has operated successfully on oils ranging from 11 to 36°Bé, containing from 6 to 85 per cent of emulsion. With electric current costing 1½ cts. per kilowatt-hour, costs for this process range between 1.5 and 3.5 cts. per barrel, including the above-mentioned royalty, repairs, power, steam, labor and all fixed charges. The initial cost per treater, with auxiliary equipment, varies from $1,300 to $3,000, depending upon the number of treaters in the plant. Maintenance averages about $15 per treater per year.

The electrical method of dehydrating is widely used in the California and Gulf Coast fields, and is particularly popular in the California fields, where it is said 95 per cent of the emulsion produced is treated by it.[2] Due to the difficulty of securing electric current, it has not come into common use in other American fields.

Dehydrating by Chemical Treatment.—Petroleum emulsions respond to treatment with various chemical reagents, which operate either to dissolve the films enclosing the water globules by direct solvent action, or by neutralizing the negatively charged water globules, through the introduction of some readily adsorbed cation. Thus, ether and mixtures of ether and carbon disulphide, if agitated with emulsion, will liberate the oil due to their solvent action on the asphalt which composes the oil films about the water globules. Experimental data have shown that either hydrochloric acid, ferric chloride or ferric nitrate are effective as electrolytes in neutralizing the negatively charged globules and precipitating the water.

A patent issued to F. M. Rogers in 1919 (U. S. Patent 1,299,385) covers the use of water-soluble alkaline salts of sulfonic acid, obtained by sulfonating either a coal tar or petroleum. Such compounds form a colloidal solution in water which resembles a crude soap. They do not, however, form colloidal solutions in oils. The addition of ¼ to 4 lb. of sodium salt of a sulfonated mineral oil per barrel of emulsion, and heating to 150°F. for a brief period of time, will result in the desired separation of the water.

Water-soluble colloids added to the emulsion will in some cases neutralize the effect of the emulsifying agent dissolved in the oil. Considerable success has been had with "Tretolite,"* a chemical compound of this type, in the mid-continental fields. Tretolite was first marketed as a crude solid soap, and contained about 83 per cent of sodium oleate, with small amounts of sodium resinate, sodium silicate, phenol, paraffin and water.[2] One per cent of this compound added to the emulsion in a water solution, agitated, and maintained at a temperature of 150°F. for from 12 to 72 hr., will usually be successful in reducing the water content to less than 1 per cent. Liquid Tretolite, a later development, contains about 25 per cent of sulfonated oleic acid, the excess acid being neutralized with caustic soda. In the field this liquid, diluted to a 1 per cent solution, is mixed with the oil by pumping both fluids through piping into a wooden tank containing hot water, in which the separation of the clean oil is accomplished. The quantity of chemical used, the temperature and time of treatment must be varied in accordance with the character of the emulsion.

* Manufactured by W. S. Barnickel & Co., St. Louis, Mo.

The great difficulty encountered in the use of a water-soluble substance is that of passing it through the oil film which encloses the water globules. Agitation accomplishes this in part, but imperfectly. Dodd[5] has suggested the use of a mutually soluble reagent, and has found phenol (carbolic acid) effective. A large quantity of the reagent is necessary when used alone, but when mixed with some strong positive ion, such as sulphuric, hydrochloric or acetic acid, the quantity of phenol may be greatly reduced. As little as 0.5 per cent of phenol with 0.15 per cent of sulphuric acid was found to be effective in demulsifying California emulsions. Dodd advances the theory that the sulphuric acid is the active agent in neutralizing the ionic charge on the water globules, the phenol, soluble in both the water and the oil, being of use chiefly in passing the acid through the oil film.

Dehydrating by Centrifugal Devices.—The differential effect of centrifugal force operating on the components of oil-water mixtures has long been utilized in a small way in making laboratory determinations of the percentage of water in petroleum, but it is only within the last few years that the method has been adapted to the dehydrating of petroleum emulsions on a large scale.

A centrifuge capable of bringing about complete separation of the two fluids in emulsified form must have a high speed of rotation. The machines so far developed for large-scale continuous operation consist of a metal bowl mounted on the upper end of a vertical spindle, driven by a direct-connected electric motor or steam turbine. Belt-driven machines may also be secured if desired. The oil-water mixture, usually preheated to reduce viscosity, is fed into the bowl at its center through a pipe which discharges into the bowl near the bottom. The selective action of centrifugal force then causes the heavier of the two fluids—water—to move outward as it moves upward toward the outlets in the cover of the bowl. A clear-cut line of separation is developed between the two fluids, the position of which depends upon the percentages of water and of oil present. Clean oil overflows through an outlet in the top of the bowl near the center, while water escapes through a second outlet near the outer circumference of the bowl. Sand and other suspended impurities tend to follow the water, though the coarser solids generally remain in the bowl and must occasionally be removed by hand methods after stopping rotation and removing the cover.

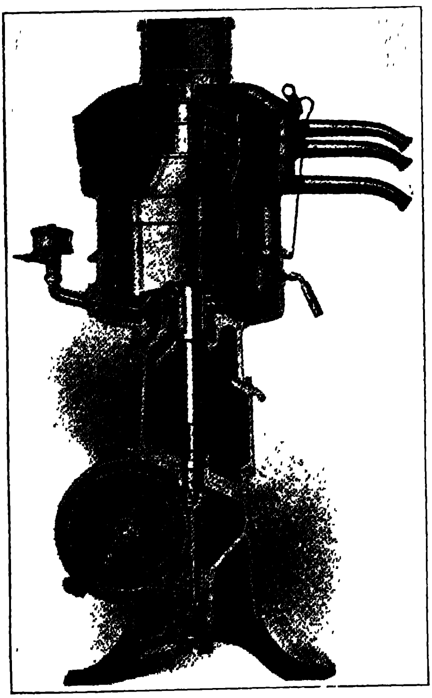
Two types of centrifuges have entered the field of dehydrating crude petroleum emulsions and have achieved sufficient success to warrant brief description.

The Sharples supercentrifugal process* utilizes a machine of simple bowl type as described above (see Fig. 285) driven by a direct-connected steam turbine at a speed of 17,000 revolutions per minute, developing a separating force 16,900 times the force of gravity. The oil to be treated is given preliminary heat treatment by means of steam coils placed in a 250-bbl. tank partially filled with water through which the emulsion rises. Heated emulsion is led to the centrifuge from an overflow pipe near the top of the tank. Temperatures maintained range from 110 to 180° F. if complete separation of the emulsion is required. The manufacturers state that greater efficiency is secured with very refractory emulsions through the addition of "suitable chemicals" to the emulsion in the heat-treatment tanks. The centrifuge discharges two products: clean oil, which is ready for shipment, and water which may at times contain small percentages of B. S. or unseparated emulsion. The Sharples centrifuge of the size manufactured for this class of service (No. 6) has a capacity ranging from 100 to 200 bbl. of clean oil per 24 hr., depending upon the character of the emulsion. The cost of a single centrifuge is $2,000, and it is estimated (1921) that a five-unit plant can be installed for about $18,000, including three additional rotors, necessary steam boilers, pumps, tank and other accessories. The operating cost for a five-unit plant is estimated at $62 per day.

* Sharples Specialty Co., New York City.

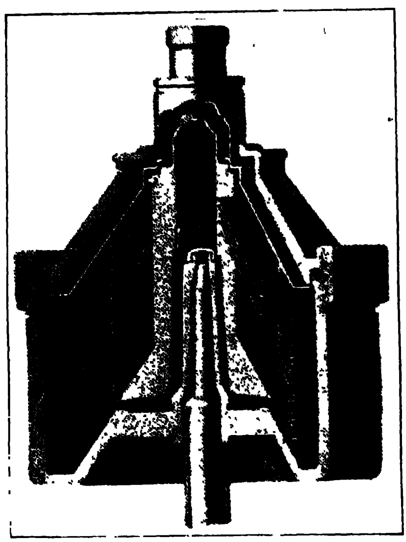
(*Courtesy Sharples Specialty Co , New York*).

FIG. 285.—Battery of Sharples centrifuges.



(*DeLaval Separator Co , New York*).

FIG. 286.—Sectional view of DeLaval oil purifier.



(*DeLaval Separator Co , New York*)

FIG. 287.—Sectional view of bowl of DeLaval oil purifier.

By November, 1921, fifty-seven centrifuge plants having a daily capacity of 23,000 bbl. of emulsion had been installed—chiefly in the mid-continental fields.

The DeLaval oil purifier,* illustrated in Figs. 286 and 287, is unique in the construction of the centrifuge bowl, which is equipped with a series of thin sheet metal cones, mounted one over another on the central spindle in such a way that narrow spaces are preserved between them. The oil to be treated is fed into a pipe penetrating the center of the cover of the bowl and passes down to the bottom, whence it flows out and up through a series of circular holes which penetrate the cones, and is distributed in thin layers between them. Here, due to centrifugal action, separation of water and solid impurities from the oil takes place. Water and solids, being heavier than oil, flow along the lower surface of each cone toward the periphery of the bowl, where they are led into the water discharge channel. The oil, cleaned of its impurities, is forced toward the center of the bowl, flowing along the upper surfaces of the cones to an annular channel surrounding the central feed pipe, through which it overflows into the oil discharge pipe.

For a given speed of rotation and gravity difference between the oil and water, the bowl soon develops a fairly well-defined line of separation between the two fluids which automatically adjusts itself to varying proportions of oil and impurities. If clean oil enters the bowl, there will be no discharge through the "sludge" outlet, while if water only is passed through the bowl, nothing will flow from the oil outlet. The bowl is designed for maximum sludging capacity and has a relatively large dirt-holding capacity (168 cu. in. in the No. 600 machine).

The practical advantage of this patented bowl construction, aside from any advantage that may exist through securing a more complete separation of the water and oil, lies in the fact that the desired result is accomplished with a much smaller speed of rotation. The No. 600 machine, which can be purchased either with a direct steam turbine or electric motor drive, has a rated capacity of from 10 to 15 bbl. of crude per hour, and is operated at a speed of 6,000 revolutions per minute. The cost of this machine is $1,500 per unit (1921). Using electric power costing 1½ cts. per kilowatt-hour, the manufacturers claim that a small installation of DeLaval purifiers may be operated at a cost of about 4 cts. per barrel, including all charges, for crudes of moderate B. S. content.

Other dehydrating processes which have been proposed but not used to any great extent on a working scale may be mentioned in passing, though they are unimportant from a practical point of view at the present time.

Filters of various types have been proposed for removing water from oil, but filtration methods have as yet only been practically applied to the separation of water from refined lubricating oils. The filtering medium is first wetted with oil, after which oil may pass through but water is left on the filter, which, however, soon becomes clogged. The filtering process has been improved somewhat by combining electrical treatment with it (see U. S. Patent 987,114, issued to Cottrell in 1911).

Still other methods have for their object a reduction in the surface tension of the water associated with oil by introducing sharp angular solids such as sand, while others based upon the same idea attempt to separate the water by passing the emulsion through glass wool, excelsior, kieselguhr or other porous filtering media.

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CHAPTER XVII

STORAGE OF PETROLEUM

Necessity fór Large Storage Facilities for Crude Petroleum.—The market for crude petroleum is subject to great fluctuations due to variations in supply and demand. Seasonal demands on the gasoline and fuel oil markets are particularly noticeable in their effect, and increase or decrease in activity over a wide range of industries will have its influence in creating a distinct change in the demand for oil and oil products. The production of petroleum is subject to even greater fluctuation. The advent of a newly discovered field, rapidly developed by a host of small producers, each competing with the others to secure a maximum of the available oil, may result in a sudden oversupply, out of all proportion to the market demand; and the situation may persist in spite of adverse market conditions. While decline in production of oil fields usually proceeds at a more deliberate pace, its effect may be none the less noticeable, and a market developed to absorb a certain output in an isolated region where other fuels are not readily available may suddenly find its supply of oil greatly reduced as the field reaches full developent and starts on its decline.

The obvious remedy for such a condition is adequate storage facilities which will admit of oil being held in storage during periods of oversupply, building up a reserve which may be called upon to equalize the burden at times when demand exceeds supply. Oil in storage thus serves as a buffer between the producer and the consumer, and has a marked influence in checking price fluctuations.

FACTORS OF IMPORTANCE IN SELECTION OF SITE AND TYPE OF STORAGE

It is usually economical to build the storage plant in large units, grouped together in such a way and in such places as will give adequate protection against fire, ready accessibility to both the field, the market and the transportation facilities, at a minimum construction cost and a minimum cost of land. Groups of tanks or reservoirs, which are the storage units available, are called "storage farms" or "tank farms" (see Fig. 288).

In determining the location of a storage farm, such matters as accessibility—both for construction materials and oil transportation—topography, character of soil and cost of land will be matters of prime

importance. Selection of a type of storage will involve consideration of relative cost and salvage value and degree of protection afforded against seepage, evaporation and fire losses.

Accessibility.—In the construction of steel tanks or concrete-lined reservoirs for oil storage, the transportation and handling of a large tonnage of structural materials is necessary. Railroads or highways, suitable for heavy motor or horse-drawn vehicles, must therefore be available. If the site selected is not in or near a city or town, living accommodations and other facilities, such as water supply, must be provided for the attendants who look after the "farm" after it is placed in service. The area selected must be conveniently located with respect to the refinery, pumping station or other transportation terminal which it is intended to serve.

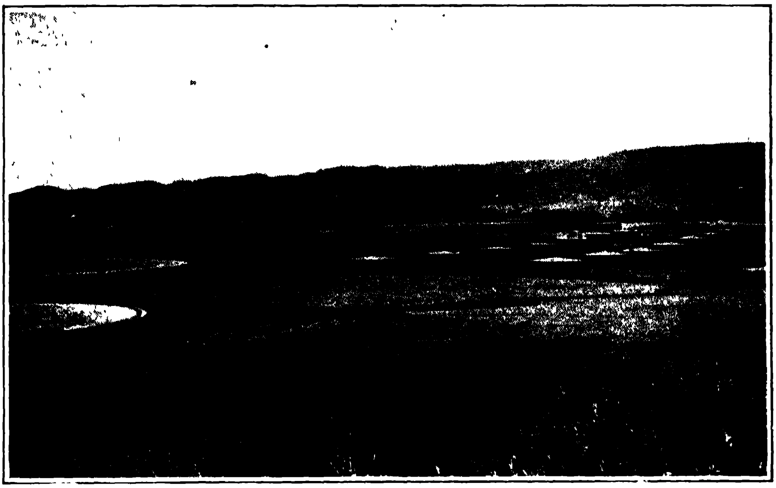


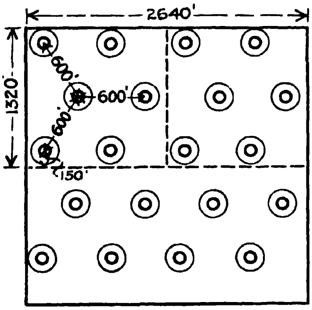
FIG. 288.—A typical storage "farm" equipped with both steel tanks and concrete-lined reservoirs.

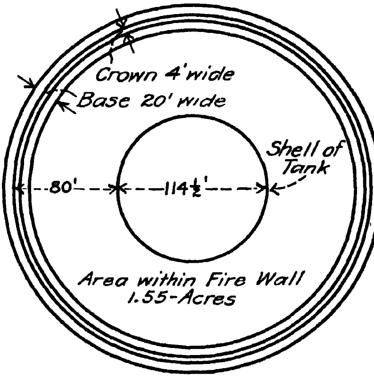
Topography.—The site selected should be fairly level. Tanks must have a level foundation, and since they are often of large diameter, excavation costs will be high if sloping ground is selected. Similarly, embankments for a reservoir will be more costly if excavations must be made on a hillside. In some cases, however, where gravity flow from the storage is desirable, an elevated position, perhaps on sloping ground, will be deliberately selected, the additional cost of excavation being offset by the cost of equipping and operating a pumping plant which would otherwise be necessary.

Character of Soil.—If tanks are to be used, it will be important to select firm ground which will not shift under the weight of the tanks and their contents. In the higher tanks, the weight imposed will amount to a ton or more on each square foot. If marshy land is selected, it may be necessary to prepare supports by driving piles to prevent the tank from sinking into or otherwise displacing its foundations. Wet ground is also detrimental to the steel bottoms of such tanks, particularly if the water is saline. Alkaline soils may cause rapid corrosion of metal, even though the soil is fairly dry. The soil should be homogeneous in texture, preferably a sandy clay in which clay predominates.

Cost of Land.—Since a large space will ordinarily be required for the storage system, the cost of the land occupied will be a consideration in the selection of a site. This may become a factor of transcendent importance if the storage must be located in or near a city, or in other situations where values, as determined by the suitability of the land for other purposes than oil storage, are high. In such cases, the cost of the necessary acreage may amount to 50 per cent of the total cost of storing the oil.

Because of the fire risk, the area selected for the storage farm should be set apart and not used for other purposes, such as for wells, dwellings or other oil field plant.





(*After O. U. Bradley in Trans. Am. Inst. Mining & Metallurgical Engrs.*)

Fig. 289.—Illustrating staggered arrangement of tanks.

Fig. 290.—Illustrating position of fire wall about oil storage tank.

For the same reason, the tanks or reservoirs must be spaced apart sufficiently, and fire walls or earthen levees must be constructed, to prevent fires from spreading from one container to another (see Fig. 290). Often a section of land on the edge of an oil field, near the initial pumping station on the pipe line which carries the product of the field to market—acreage which it is felt certain will never be of value as productive oil land—will be the site selected for the field storage. Storage facilities for a refinery must ordinarily be located on a site immediately adjoining the plant, and in such cases land values, even through abnormally high, must ordinarily be subordinated to convenience and economies in operation.

Steel tanks of 55,000-bbl. capacity, spaced 500 ft. apart, center to center, will occupy 5.74 acres per tank. If land is valued at $100 per acre, the cost will be a little over 1 ct. per barrel of storage capacity. Staggering the locations in alternate rows is more economical in acreage occupied than if a rectangular pattern is followed (see Fig. 289). Concrete-lined reservoirs 528-ft. in diameter and 22 ft. deep, having a capacity of 750,000 bbl., may be spaced about 1,000 ft. apart, center to center, each reservoir occupying an area of about 13 acres. On the same valuation per acre assumed in the case of steel tanks, the cost of land will be only about $.0017 per barrel of storage capacity.

First cost and salvage value of the containers provided for storing the oil will be important considerations in the selection of one type in preference to another. Steel tanks are found to be more expensive, costing from three to four times as much per barrel of storage capacity as concrete reservoirs, but they possess certain advantages in lower evaporation and seepage losses which may, in the case of light oils, easily offset the additional first cost. Steel tanks in even the larger sizes can be readily

taken apart and moved to a new location. Consequently their salvage value will be much higher than that of a concrete reservoir, which will ordinarily be of little or no value when the field which it serves is exhausted. Both types of storage are long-lived, the deterioration in each case being scarcely measureable, but it is generally conceded that the steel tank has a shorter life. While deterioration of the steel plates may be largely prevented by occasional painting, the inner bottom surface is subjected to continual contact with water, which, settling out of the oil, is usually saline, and may result in corrosion of the bottom plates long before the sides and top show any signs of deterioration.

Seepage losses will be negligible in the case of steel tanks, being confined to small leaks between seams, due to inefficient calking or to strain imposed on the plate joints. Such losses are also unimportant in properly constructed concrete-lined reservoirs, but are generally regarded as more probable through concrete linings than through riveted steel plates, especially if cracks develop in the concrete lining due to unequal expansion or contraction, or to buckling or subsidence as a result of improperly prepared foundations.

Evaporation Losses.—The loss of petroleum while in storage through evaporation is a factor of great economic importance, and one which has not received the attention it deserves until very recently. Evaporation during storage is particularly noticeable in the lighter oils, and is variously estimated at from 1 to 25 per cent, depending upon the volatility of the oil, the temperature, wind velocity, amount of agitation which the oil undergoes and the length of time in storage. Investigations of the U. S. Bureau of Mines[16] have shown that petroleum of 34° in Baumé gravity, stored at an average temperature of 78°F., in 500-bbl. steel storage tanks, may suffer a loss of 4.5 per cent in bulk during a period of storage extending over only 10 days. In filling a storage tank over a period of 5 days, with 40.7° Bé. oil, at an average temperature of 37°F., with the tank hatch open, a loss of 6 per cent in volume resulted, accompanied by a reduction of 2.46° in Baumé gravity. While normally the losses will probably be less than this, evaporation will still be an important consideration, since the amount of oil so lost represents the lighter and more valuable gasoline-forming constituents. The evaporation of even 1 per cent of the contents of a 55,000-bbl. tank of petroleum represents a loss of 550 bbl., which, at current gasoline prices, represents a loss of nearly $6,000.

The temperatures prevailing in oil stored in steel tanks on a hot summer day may be sufficient actually to distill off some of the lower boiling constituents. Vapors escaping from the oil accumulate in the free space under the roof of the tank or reservoir until the vapor pressure of the oil is equalized. Once equilibrium is established between the vapor pressure of the oil and the pressure of the free vapor above the oil surface, no further evaporation occurs unless the vapor is allowed to escape from the tank. Generally, the roof of a steel tank is not gas-tight—the covering over a large reservoir is seldom so—consequently, vapors escape and evaporation continues indefinitely.

It is apparent that while temperature is an important consideration in this process, security against gas leakage is the controlling factor, and if the leakage of gas from the container could be prevented, evaporation losses would be much reduced. It is seldom feasible to accomplish this. A vent must be provided to prevent the gas from developing unsafe pressures within the tank. Air must be admitted or gas must be permitted to escape when the oil level rises or falls as oil is withdrawn or added. Most reservoirs and many steel tanks are roofed over with wooden sheathing, perhaps covered with roofing paper, a type of construction which is never secure against gas leakage. Under such circumstances, the wastage by evaporation on a warm windy day may account for a substantial loss. Investigations have shown that if the tank roof is not secure against gas leakage, evaporation losses are greater on a cool windy day than during a hot quiet day.

Various methods have been proposed and applied to reduce evaporation losses, particularly in steel tankage. These will be described in a later section of the present chapter. It will be apparent, on comparing the two principal types of oil storage, that the steel tank is ordinarily superior to the concrete reservoir in curtailing evaporation losses, though the latter would appear to have the advantage of lower oil temperatures.

Petroleum probably undergoes its greatest loss during the first few days of storage. Agitation of the oil during its admission to the tank doubtless contributes largely to this result. Once the oil is completely at rest, its evaporation rate will be somewhat reduced. There is, however, continual vertical movement in stored oil; the surface oil, being reduced in gravity by loss of its lighter constituents, sinks and is replaced by lighter oil from lower strata. It is apparent that the evaporation rate must decrease as time goes on, since the oil is continually decreasing in Baumé gravity, a change which is indicative of reduction in the amount of low-boiling constituents.

Fire risk is an important element in the selection of a type of storage for large volumes of oil. Losses involved in the burning of a large tank of oil are so great that their prevention is worth the expenditure of considerable sums. Preventive measures include the prevention of gas leakage, provision of lightning arresters, isolation of one container from another and devices to prevent overheating. A steel roof is obviously more secure against fires from an external source than a wooden roof. While the fire risk would appear to be greater in the case of concrete reservoirs, due to the frequent use of wooden roofing on this type of storage, the oil temperatures, as explained above, are generally lower than the temperatures prevailing in steel tanks. There are few cases on record of oil fires in large concrete reservoirs, and many have occurred in steel tanks; nevertheless, the fire risk is probably greater in the case of the reservoir, because of the larger volume of oil commonly stored in it, and because of the difficulty of applying fire extinguishing devices.

Types of Storage

Containers for the storage of petroleum in bulk may be conveniently classified into two groups: tanks and reservoirs. Tanks may be made of either wood, steel or reinforced concrete. The steel tank, made of riveted steel plates, constitutes the most common type of storage. Reinforced concrete reservoirs, while comparatively few in number, nevertheless, because of their large capacity, provide storage for a comparatively large percentage of the stored oil in certain regions producing low-gravity oils, notably in California. The reinforced-concrete tank, while a comparatively recent innovation, is a promising substitute for the steel tank. Wood-stave tanks of large size (above 2,000 bbl.) are seldom met with and are not to be recommended because of greater fire risk, excessive evaporation losses and because of the difficulty of keeping them tight against leakage. Earthen reservoirs are usually intended to be only of temporary use and are constructed only in cases where sudden and unexpected need for storage facilities has developed and other types of storage are not available.

Several types of steel tanks are employed for the storage of petroleum. Galvanized iron, either corrugated or plain, is often used in the manufacture of tanks of small capacity. Small and moderate sized tanks are

also commonly manufactured of black sheet steel, the sections being built up of steel plates with riveted joints, while the sections are bolted together in assembling the tank. The larger sizes of tanks, that is, those exceeding 1,500 bbl. in capacity, must be assembled on prepared foundations using riveted joints throughout.

Tanks of 100-bbl. capacity or less are usually assembled by the manufacturer and are shipped intact and ready for service as soon as placed on adequate foundations and connected with piping (see Fig. 291).

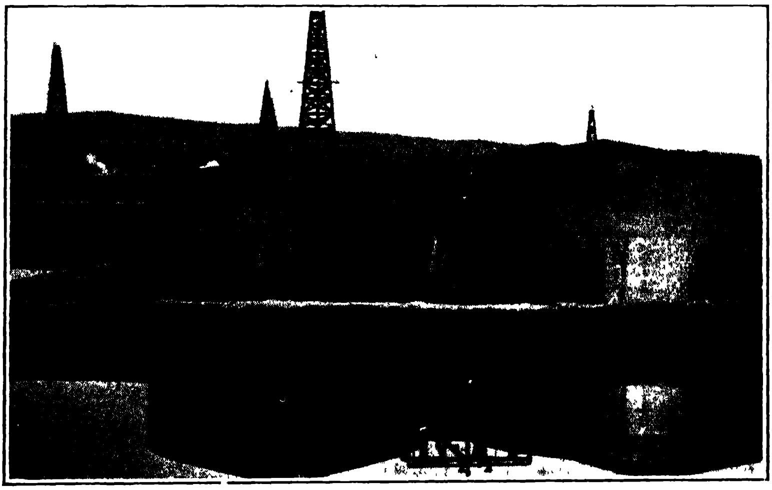


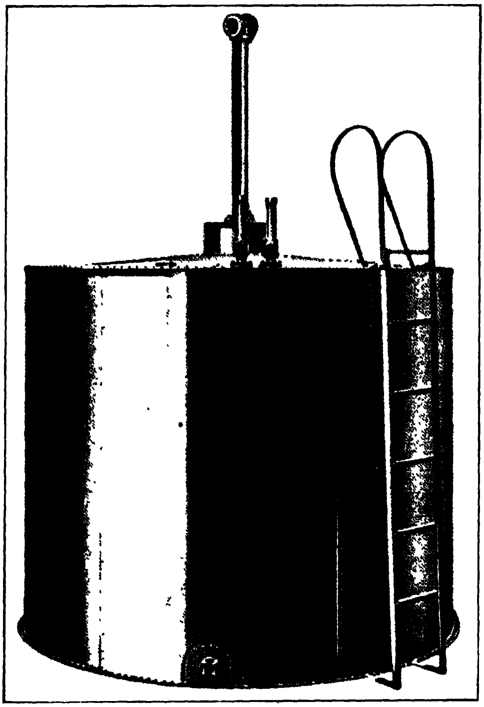
Fig. 291.—A group of corrugated steel storage tanks and earthen reservoirs.

Such tanks are often made of thin, galvanized sheet iron, and to give rigidity the metal may be corrugated, the corrugations running horizontally, around the tank. Larger tanks must usually be "knocked down" and assembled in the field, though it is feasible to move a tank as large as 500 bbl. in capacity with a 5-ton motor truck. Many operators are equipped for the manufacture of small tanks of 100 bbl. or less in their field shops, but it will not usually be economical to undertake the fabrication of larger tanks without special facilities which the average operator cannot afford to own.

Intermediate sized tanks are often of the "bolted" variety, in which the tank is shipped into the field in sections which have merely to be bolted together. Aside from convenience in handling and assembling, such tanks possess the great advantage that they can be readily taken apart and moved to a new location if desired. Fig. 292 illustrates some of the more important features of bolted tank design furnished by one well-known manufacturer (see also, Fig. 267).

Wood-stave tanks have been rather widely used for the storage of oil in certain American fields, but are seldom met with in sizes exceeding 2,000

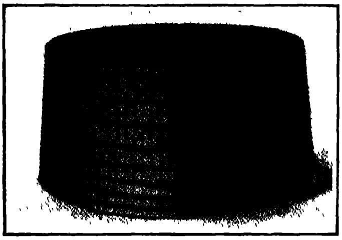
bbl. in capacity. The 500- and 800-bbl. wood-stave tanks are the most common sizes. The material is either pine or redwood, which is shipped to the site on which the tank is to be erected as strips or "staves," so shaped that on being placed side by side around a circular wooden bottom, they form a tank as high as the staves are long. The staves are held firmly together by metal hoops or bands which encircle the tank on its



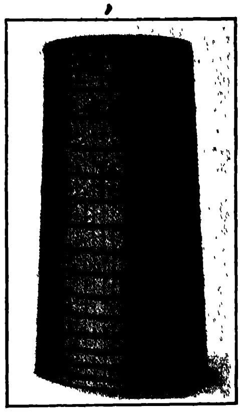
(*Parkersburg Rig & Reel Co., Parkersburg, W. Va.*)
FIG. 292.—Typical bolted tank.

outer circumference. If the stave edges are carefully beveled to accord with the desired radius of the tank, such a tank can be made fairly secure against leakage. Tension in the metal bands is adjustable by means of turnbuckles or simple screw devices (see Figs. 293, 294 and 295). The joint between the staves and bottom is mortised, tongue-and-groove fashion, and the usual design provides that the tank is slightly smaller at the top than it is at the bottom. Wood-stave tanks are never as satisfactory for the storage of oil as they are for the storage of water. Expansion of the wood under the influence of water renders the wood-stave tank practically watertight. This tendency of the wood to expand is quite absent when in contact with oil, so that the only security against leakage between staves must result from accurate fitting of the staves and tension in the steel hoops.

To offset this tendency of wood to shrink when in contact with oil, a patented tank has been devised and is available on the market, in which the edges of the staves are grooved in such a way that water may be admitted between all joints, thus swelling the staves and reducing, or even entirely preventing, leakage of oil. This tank is provided with a watertight closed top which is depressed below the upper ends of the staves. Holes bored half through the staves admit water to the channels and the stave and cover joints may be kept permanently tight by keeping the space above the cover filled with water (see Fig. 295).



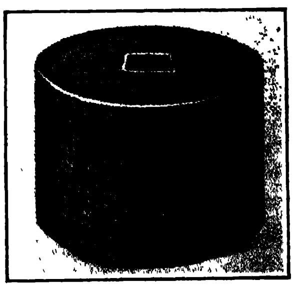
(Parkersburg Rig & Reel Co.)
FIG. 293.—Common form of wood-stave tank for oil storage.



(Parkersburg Rig & Reel Co.)
FIG. 294.—Gun-barrel type of wood-stave tank for oil storage.

RIVETED STEEL TANKS

Steel tanks for the storage of petroleum are always cylindrical in form. Though storage tanks having their axes placed horizontally are sometimes met with—particularly in tanks of small size used for the storage of fuel oil and gasoline—it is universal practice in the case of the larger sized tanks to place the axes vertical. Such tanks are built up in horizontal "rings" riveted together, one above another, with a steel bottom consisting of riveted steel plates, and a low conical roof, sometimes of wooden sheathing, though preferably of steel plates, riveted together in the same manner as the sides and bottom (see Fig. 296). Two flanges made by bending angle iron to the tank radius are used, one for connecting the cylindrical shell with the bottom, and the other for connecting the shell with the roof. The shell, roof and bottom are securely riveted to these flanges, and all joints are carefully calked to prevent leakage. Intake and suction piping with a screened swing pipe and a means of



(Pacific Tank Co., San Francisco).
FIG. 295.—Water-top wood-stave pipe for oil storage.

controlling its position in the tank, a stairway leading to the roof, manholes for access to the interior, gaging and ventilating hatches, complete the equipment of the tank.

Capacities of steel oil storage tanks range from 25 to 80,000 bbl.; but for large-scale tank farm storages the 55,000-bbl. size has been used

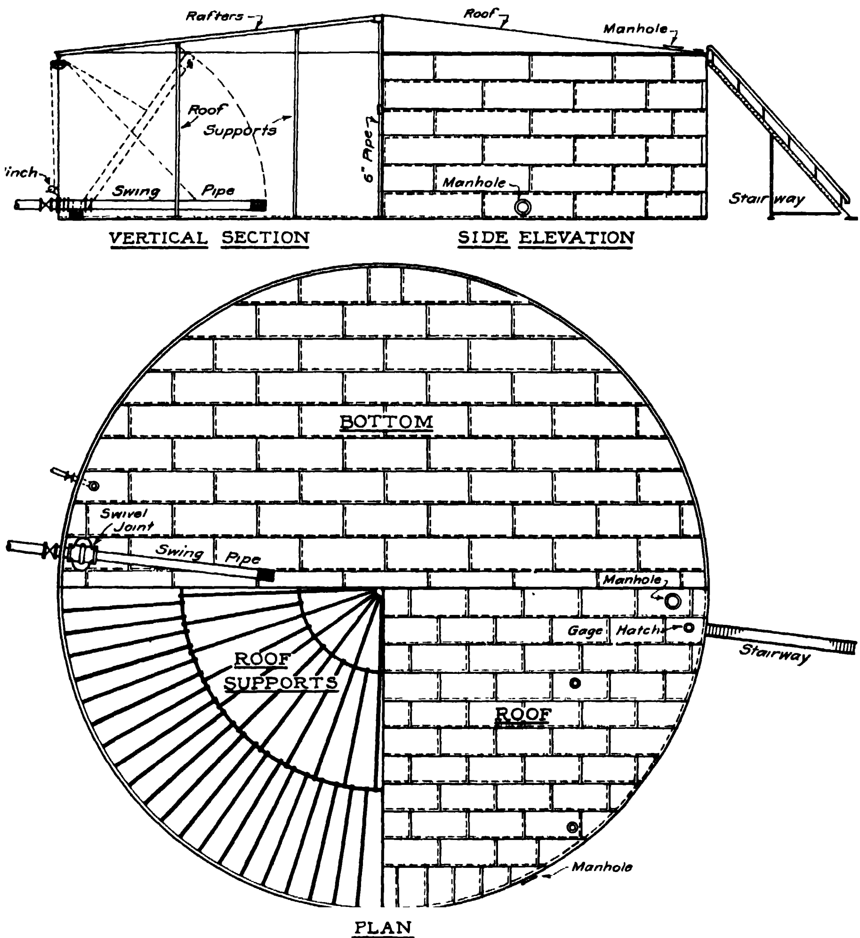


FIG. 296.—Riveted steel tank, 55,000-bbl. capacity.

more than any other, and units of this size have become almost standard in large installations. Recently, the tendency has been toward the use of larger tanks, many 80,000-bbl. tanks having been installed in the California fields in 1923. Table XL gives the more important dimensions of riveted steel tanks, together with corresponding capacities, weights and character of joints.

During the flush production of the southern California fields in 1922–1923, many 80,000-bbl. tanks were built, and late in 1923 six 178,000-bbl. riveted steel tanks were contracted for by a California oil company. The latter size of tank is 175 ft. 9 in. in diameter and 42 ft. high and is fitted with a flat 3/16-in. steel top, depressed 6 in. to form a water seal. The first ring has a thickness of 1 in. and has double butt strap, sextuple riveted joints. The total weight of the tank is about 720-tons. It is thought that the 80,000-bbl. tank marks about the limit of economy in steel tank construction, the 178,000-bbl. tank costing 6 cents more per barrel of capacity, but more efficient utilization of land acreage in the case of the larger tank sometimes off-sets this.

TABLE XL.—SIZES, WEIGHTS, CAPACITIES AND CHARACTER OF JOINTS FOR RIVETED STEEL OIL STORAGE TANKS*

Capacity barrels	Diameter, ft.	Height, ft	Shell		Thickness of bottom U. S gage no.	Size angles	
			No rings	Thickness U S gage no		Bottom flanged, in.	Top flanged, in.
100	8 9/12	10	2	10	10		
300	15	10	2	7–7	7	2½ × 5/16	2½ × ¼
500	20	10	2	7–7	7	2½ × 5/16	2½ × ¼
750	20	15	3	7–7–7	7	2½ × 5/16	2½ × ¼
1,000	20	20	4	7–7–7–7	7	2½ × 5/16	2½ × ¼
2,000	25	25	5	6–6–6–6–6	3	2½ × 5/16	2½ × ¼
2,000	30	16	3	6–6–6	3	2½ × 5/16	2½ × ¼
2,500	30	20	4	6–6–6–6	3	2½ × 5/16	2½ × ¼
3,000	30	25	5	6–6–6–6–6	3	2½ × 5/16	2½ × ¼
3,500	30	30	6	3–6–6–6–6–6	3	2½ × 5/16	2½ × ¼
5,000	35	30	6	3–6–6–6–6–6	3	3 × 3/8	2½ × 5/16
5,000	38	25	5	6–6–6–6–6	3	3 × 3/8	2½ × 5/16
6,000	38	30	6	3–6–6–6–6–6	3	3 × 3/8	2½ × 5/16
6,500	40	30	6	0–3–3–6–6–6	3	3 × 3/8	2½ × 5/16
10,000	50	30	6	0–3–6–6–6–6	3	3 × 3/8	2½ × 5/16
10,000	54	25	5	4–5–6–6–6	6	3 × 3/8	2½ × 5/16
15,000	66	25 3/12	5	1–3–6–6–6	6	3 × 3/8	2½ × 5/16
20,000	76	25 3/12	5	0–3–6–6–6	6	3 × 3/8	2½ × 5/16
25,000	86	25	5	00–1–5–6–6	6	4 × ½	2½ × 5/16
30,000	86	30	6	0000–00–1–5–6–6	6	4 × ½	2½ × 5/16
37,500	95 9/12	30 1/12	6	7/16-in.–000–0–3–5–6	6	4 × 5/8	2½ × 5/16
55,000	114 7/12	30 5/12	6	½-in.-7/16-in.–000–0–3–6	6	4 × 5/8	3 × 3/8

* From Lucey Corporation's Catalog No. 8.

Steel Tank Design.—A 55,000-bbl. steel tank will contain about 8,650 tons of 20°Bé. petroleum. Pressure against the cylindrical shell of a tank filled with 20° oil to a depth of 30 ft. increases in a constant ratio from zero at the top surface to 1,680 lb. per square foot at the bottom, which latter figure represents also the weight of oil on each square foot of the bottom plates.

It is obvious that the greatest strain, due to the weight of the oil, will fall on the vertical seams connecting the individual plates forming the rings. This is due to the outward pressure, normal to the walls, tending to increase the diameter of the cylinder, thus putting strain on the joints which resist radial expansion. The horizontal seams connecting the several rings will normally be subjected to comparatively little strain from the weight of the oil in the tank, so that they may be designed merely to withstand the dead load of the tank itself. These variations in strain imposed on different portions of the tank are allowed for by varying the thickness of the metal plates and the number, size and arrangement of rivets at the joints. Table XLI gives specifications for a 55,000-bbl. tank, 114 ft. 6 in. in diameter and 30 ft. deep.

TABLE XLI.—SPECIFICATIONS COVERING THICKNESS OF METAL AND CHARACTER OF JOINTS FOR A 55,000-BBL. RIVETED STEEL OIL STORAGE TANK*

Part	Thickness, in.	Weight per square foot, lb	Horizontal riveting—all single rows		Vertical riveting			
			Diameter of rivets, in	Pitch, in.	Rows	Diameter of rivets, in.	Pitch, in	Distance between rows, center to center, in.
Bottom sketch plates	5/16	12.75	1/2	1 1/2				
Bottom rectangular plates	1/4	10 20	1/2	1 1/2				
First ring	9/16	22 95	1	2 1/2	Triple	3/4	3	2
Second ring	1/2	20 40	7/8	2 1/2	Double	3/4	3	2
Third ring .	13/32	16.58	3/4	2 1/2	Double	3/4	2 1/2	2
Fourth ring .	5/16	12.75	3/4	2 1/2	Double	5/8	2 1/4	1 3/4
Fifth ring. .	1/4	10.20	5/8	2	Double	5/8	2 1/4	1 3/4
Sixth ring	1/4	10.20	5/8	2	Double	5/8	2 1/4	1 3/4
Roof plates	3/16	7.65	3/8	1 1/4				

* After C P Bowie in U S Bureau of Mines, *Bull* 155

It can be demonstrated mathematically that above a certain "critical capacity," which varies with the type of tank (see Table XLII), the most economical height for a steel tank is constant and that below this capacity, the most economical ratio of diameter to height is constant.[9] Certain other constants useful in calculating weights of various types of tanks are also indicated in Table XLII.

While it is customary to place the greater part of the metal in a tank in the cylindrical shell, it must be remembered that the roof and bottom, while subjected to smaller stresses, nevertheless, are the parts which deteriorate most rapidly. The bottom is subjected to corrosion both on its lower side by contact with earth, and on its upper side by saline water which settles from the oil. The roof must bear the brunt of any deterioration which may result from exposure to the weather, and in addition, is subjected to corrosive sulphur and other gases derived from the oil. The careful designer will therefore not reduce the thickness of the roof and bottom plates to that barely necessary to resist the stresses imposed.

TABLE XLII.—IMPORTANT FACTORS IN STEEL TANK DESIGN

Type of tank	Conical steel roof	Water-top roof	Wooden roof and supports	Open tank
Weight of top, bottom and supports per square foot of bottom area, lb	16.75	17 40	11.20	8.60
Critical capacity, bbl	4,000	3,900	4,820	5,450
Most economical height (for tanks above critical capacity), ft	32 4	33.1	26 6	23.2
Most economical ratio of diameter to height (below critical capacity)	0 92	0 876	1.36	1.77
Most economical diameter of tank (for capacities below critical capacity), ft	1 87 $C^{1/3}$	1 84 $C^{1/3}$	2.13 $C^{1/3}$	2.33 $C^{1/3}$
Minimum weight of tank (above critical capacity), lb	5.8 C + 11,500	5.9 C + 11,500	4.75 C + 11,500	4.16 C + 11,500
Minimum weight of tank (below critical capacity), lb	137 $C^{2/3}$	139 $C^{2/3}$	120 $C^{2/3}$	110 $C^{2/3}$

Note: In this table, C = capacity of tank in barrels (42 gal.). A tensile strength of 55,000 lb. per square inch and a safety factor of 3 are assumed for the steel. The efficiency of joints is assumed to be 0.70. The minimum thickness of steel is taken at $\frac{3}{16}$ in. The weight of a cubic foot of oil is assumed to be 60 lb.

The riveted steel tank, while well designed to withstand internal pressure, offers comparatively little resistance to external forces, particularly when empty. Wind pressure may at times exceed 40 lb. per foot of exposed surface, a unit force which, if applied to the resisting surface of a 55,000-bbl. tank, would amount to nearly 50 tons.

Such a tank would weigh 180 tons or more, so that there is no danger of the tank being overturned. The wind pressure might be sufficient, however, in extreme cases, to collapse the tank, the only security against collapse from an external force being that offered by the roof and the bottom flange to which the shell is riveted. Snow loads may amount to 30 lb. per square foot in cold climates, or a total load on the roof of a 55,000-bbl. tank, of 154 tons.

Some designs specify the use of steel cables attached to the inner walls of the shell and stretched taut across four diameters of the tank at such distances apart that the tank area is divided into 45° segments, giving the appearance in horizontal projection, of spokes in a gigantic wheel.[7] The cables may be arranged in two horizontal planes, one about 10 ft. above the bottom of the tank, and the other 10 ft. below the top flange, the ropes in the two planes being staggered with respect to each other so that the shell in a 55,000-bbl. tank is braced at intervals of about 20 ft. around the entire circumference. The cables used for this purpose are about ⅝ in. in diameter, discarded sand lines from the drilling rigs often being used. This practice has led to the name "sand line reinforcement" being applied to it. Such reinforcement not only assists in resisting internal forces, but gives the tank a certain rigidity which it does not otherwise possess, thus minimizing any tendency it may have to collapse on the application of excessive wind pressure.

Another strain to which the steel tank may be subjected in service is that due to the development of abnormal pressure conditions in the air space under the roof of the tank. The roof of a steel tank is intended to be gas-tight, or practically so, and any change in the fluid level of the oil in the tank, without providing for the admission or escape of air, might result in the establishment of pressures somewhat above atmospheric within the tank when the fluid level is raised, or a partial vacuum may result if oil is withdrawn. Mere difference in temperature between day and night of, say, 40°F., without change in the fluid level and without escape of air or gas, would result in an increase in air pressure within the tank of 1 lb. per square inch. If this pressure were applied to the entire area of the roof, it would create a lifting force of 740 tons against the under side of the roof. This is a force 700 tons greater than the downward force due to the weight of the roof, and places considerable strain on the roof joints. This gas pressure is further increased by the expansion of the oil itself and by the tendency of the oil—especially the light oils—to develop higher vapor pressures when subjected to increase in temperature.

It is doubtful, however, whether a tank is ever subjected to the full effect of this tendency of gas and air to expand, for the reason that the roof is seldom absolutely gas-tight. If it were made so initially, operation of the expansive force of the air and vapor would probably soon open up the joints to such an extent that air and vapor would escape when the temperature increased, and air would be drawn into the tank when reduction in temperature caused contraction. "Breathing" of steel tanks in this manner, with each change in temperature, results in the loss of large volumes of gasoline vapor. At night when the temperatures are low, fresh air is drawn into the tanks. This air absorbs gasoline vapor from the oil by evaporation of the latter, and during the next day when the temperature increases, is expelled. With 28½ ft. of oil in a 55,000-bbl. tank, an increase of only 25° in Fahrenheit temperature would result in 1,876 cu. ft. of air and vapor being expelled from the tank, providing the condition of the roof permitted its escape.

Tank Foundations.—The ground on which the tank is to be erected must be carefully graded, compacted and leveled. Precautions must be taken to prevent filled ground from settling or shifting after the tank is erected, otherwise severe strains may be imposed on the tank plates. This is particularly apt to occur when the site is partly excavated and partly filled, since the filled portion is likely to settle while the ground in place is not. It is preferable to place the tank either entirely on filled ground or entirely in excavated ground. Compacting filled ground may be accomplished to some extent in the process of placing the fill, using the Fresno type of scraper and allowing the stock to pass back and forth across the fill as much as possible. Sprinkling the loose earth with water as it is placed is also effective in compacting it. Rolling successive layers of earth with a steam roller or bitulithic tamper during the placing of the fill is of course most effective, but is seldom necessary.

When the site is approximately level and thoroughly compacted, grade stakes are driven at numerous points over the surface so that their tops are precisely in a level plane as determined with the aid of a level and rod.[7] Sand or gravel is then spread over the site until a surface coinciding with the tops of the grade stakes is established. Occasionally, old steel rails may be embedded in the sand or gravel, flush with the top surface, to give greater stability to the foundations.

Precautions should be taken in selecting material for the final surfacing, to avoid earth containing alkaline salts which might cause rapid deterioration of the relatively thin bottom plates. The tank bottom should also be protected against saline ground waters which might rise through the foundations and corrode the bottom plates. Water leaking through the bottom of the tank from the inside may also form puddles which keep the under surface of the bottom plates permanently wet, causing rapid corrosion. Seepage of water from the subsoil may be largely prevented by spreading

several inches of oil sand over the entire site, using this material instead of ordinary sand or gravel in adjusting the tank foundations to final grade. If oil sand is not readily obtainable, the completed surface may be oiled and the oil worked in 3 or 4 in. with the aid of rakes.

Tank Construction.—The steel, as delivered by the manufacturer has been carefully gaged, fitted and punched, so that nothing but the riveting and calking need be done in the field. Each plate is marked to indicate its position in the tank and the side plates and angle flanges are rolled to proper curvature. Rivet holes in the plates must be accurately punched so that they match within 10 per cent of their diameter when the plates are assembled, and the rivet holes are not more than 1/16 in. larger in diameter than the rivets that are to fill them.

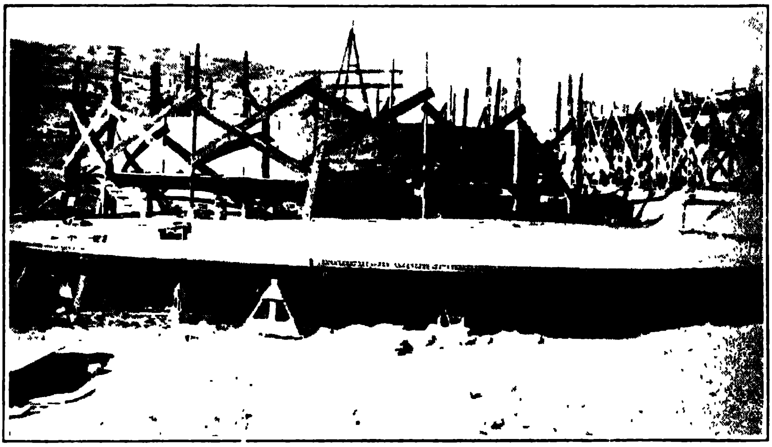


FIG. 297.- Showing two riveted steel tanks in course of construction.

Construction of the tank begins with the riveting of the bottom plates. These must be supported about 3 ft. off the ground until the entire bottom is completed. This is necessary since access must be had to the lower surface of the bottom plates in the process of riveting and in applying a coat of asphaltic or other rust-resisting paint after the riveting is completed. Substantial timber blocking or horses may be used to support the bottom during construction and it is usually held off the ground in this way until the bottom flange and first ring have been riveted in position, and the work has been tested for possible leaks by flooding the bottom with about 6 in. of water.

Riveting is preferably accomplished with the aid of pneumatic tools, a small portable compressor driven by a gas engine or electric motor furnishing the necessary air pressure. All rivets over 1/2 in. in diameter are driven hot. The bottom plates must be riveted from the inside (*i.e.*, top) but all other riveting is done on the outside of the tank.

All seams are thoroughly calked with the aid of a round-nosed pneumatic calking tool. The bottom plates and angle-iron joints are calked on the inside (or top), but all other joints in the shell and roof are calked on the outside. All castings, flanges, etc., riveted to the tank, are carefully calked, both inside and outside.

The shell of the tank is formed by ascending inside courses (see Figs. 297, 298 and 299). The steel plates are generally about 5 ft. wide and 15 ft. long, there being 24 sheets in each ring in the case of the 55,000-bbl. tank. Some designs specify plates approximately 7½ ft. wide and 18 ft. in length, thus building the 30 ft. shell of four rings instead of six, and eliminating two horizontal and four vertical seams. This

plan reduces the linear length of calked and riveted joints by more than 15 per cent. but does not permit of such accuracy of design in varying the thickness of the shell plates, as does the six-ring tank; hence the tank must be heavier. A light timber scaffolding, erected on both the inside and outside of the tank, aids in the erection of the shell. The vertical seams in the first two courses are triple-riveted, while in the third, fourth and fifth courses they are double-riveted. All horizontal seams and the vertical seams in the top or sixth course are single-riveted.

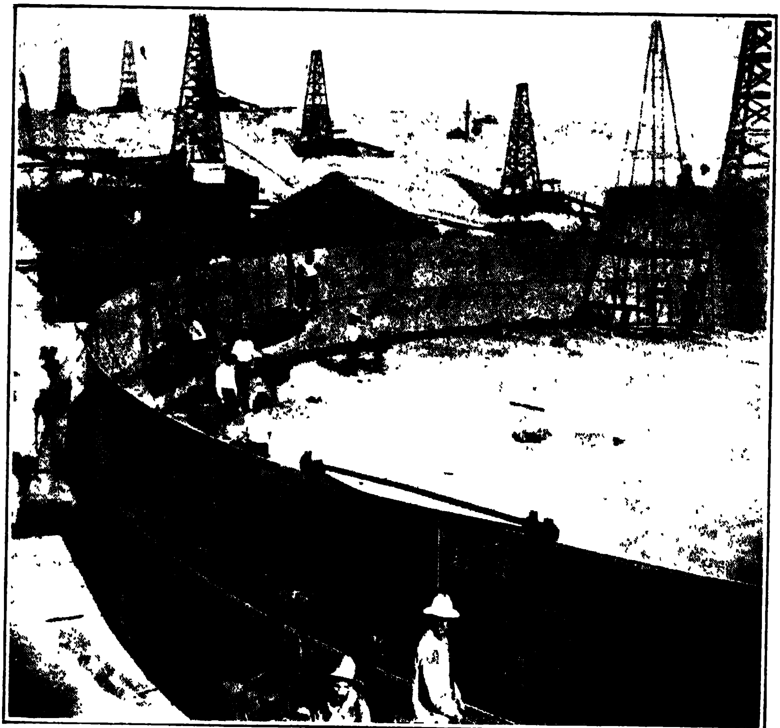


FIG. 298.—Showing method of assembling shell of large riveted steel tank.

To avoid heavy lifting over the edge of the tank shell, with possible damage thereto, most of the interior equipment of the tank, including the roof supports, will be placed on the tank bottom before erection of the shell. Erection of the roof supports may proceed simultaneously with the shell, though the rafters cannot be placed until the top ring and flange have been riveted in position. With the exception of the center post, which is a 6-in. pipe, the roof columns are all constructed of structural steel shapes, as illustrated in Figs. 299 and 300. They support, on their upper ends, two concentric rings of channel iron, rolled to the proper curvature, which in turn provide supports for the I-beam rafters.

The roof simply rests on the rafters and is not riveted to any supports except at the top flange, where it joins the top ring of the shell. This construction permits the roof to expand or contract under the influence of the pressure and temperature variations to which it is subjected, without danger of buckling the roof plates or of placing undue stresses on the joints. The roof plates are carefully riveted and calked in the same manner as the shell and bottom plates. The roof, when completed, should be gas-

tight, and specifications may prescribe that it show no leaks when tested under an air pressure equal to its own weight. Roof plates must be at least 3/16 in. thick to permit of calking. Some designs use a lighter plate and, instead of calking, prevent leakage at the joints by inserting a thread "weave," previously immersed in red lead, between the laps of the sheets before riveting them together. This method reduces the cost of construction to some extent, but the material placed between the plates deteriorates in time and leaves the roof without protection against leakage. However, as explained elsewhere in this chapter, it is doubtful, under the conditions imposed, whether a calked roof can be maintained secure against gas leakage.

The bottom ring of the shell, near its lower edge, is equipped with three pairs of companion flanges for pipe connections. One of these is for an 8-in. oil inlet pipe, one for an 8-in. oil suction pipe and the third for an 8-in. water drain. These connections, being in the side of the tank, do not permit of completely draining it, which, however, is seldom necessary. To drain the tank completely, when desired, a fourth 8-in. flanged outlet may be placed in the bottom, near the edge, connecting with a suitable drain pipe imbedded in the foundations. Two manhole flanges, 20 in. deep, are also placed in the bottom course at convenient points, the flanges being fitted with 5/8-in. bolted covers. A number of flanged outlets are also placed in the roof to provide opportunity for gaging, cleaning the swing-pipe screen and for connecting ventilating pipes, vacuum relief valves, or explosion hatches.

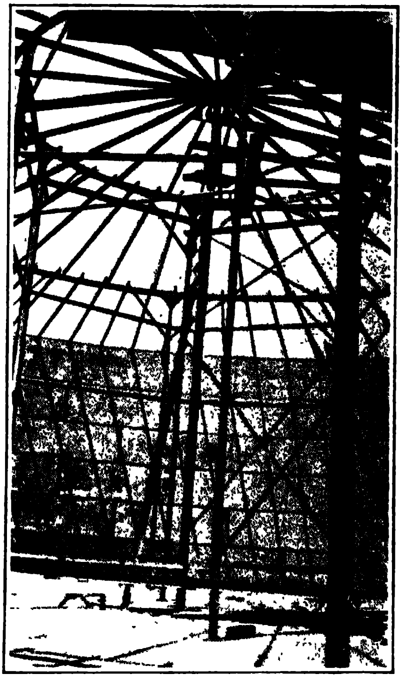


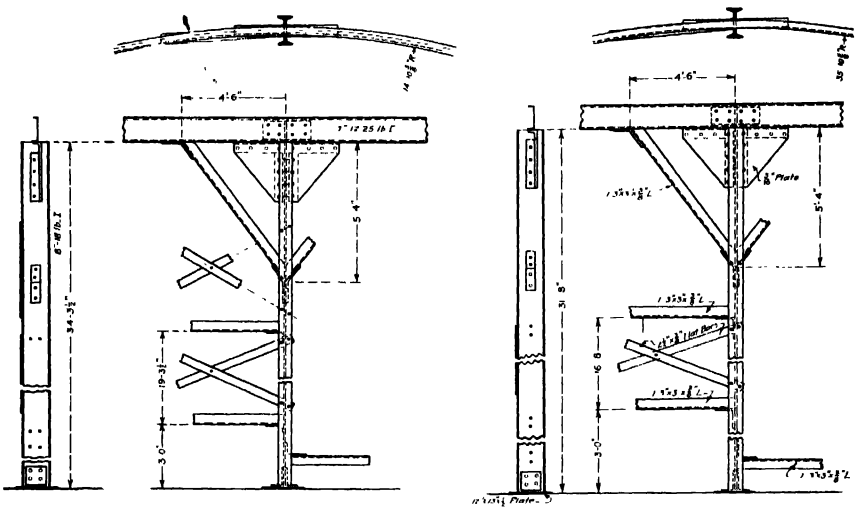
FIG. 299.—Interior of 55,000-bbl. tank during construction, showing roof supports.

The swing pipe is connected to the suction piping through a swivel joint, which may consist of two loosely screwed elbows and a short connecting nipple, or, preferably, the swivel may be of special design with gland-packed joints to permit the necessary movement without leakage. A well-designed type of swivel joint for this purpose is illustrated in Fig. 301. A chain or cable connects the free end of the swing pipe with a small hand power winch, placed either on the roof of the tank or on the side near the ground, by means of which the swing pipe may be supported in any desired position to draw oil from a selected level in the tank. Some operators equip their swing pipes with a float placed at the suction end in such a way that the float carries the full weight of the pipe, maintaining the oil suction inlet at a constant distance below the oil surface. The swing pipe need then only be hoisted with the winch when it is desired to elevate the inlet above the oil surface. Floats of sufficient size to float the heavy swing pipe have the disadvantage that they add considerable weight in case it is necessary to lift the latter with the winch while the tank is empty.

For ready access to the top of the tank, a stairway should be provided of either wood or steel, preferably the latter. This should be equipped with hand rails on either side and conveniently terminates at its upper end in a small platform 2 ft. below the edge of the roof. The gager stands on this platform while taking measurements of the fluid in the tank or gathering samples, the gaging hatch being within easy

reach of one standing on the platform. Some tank manufacturers equip their tanks with steel ladders instead of the more expensive stairways, but the convenience and safety of the gager, carrying samples of oil, possibly with greasy hands and wearing oil-soaked shoes, should offset any slight difference in initial cost.

Explosion Hatches.—Where high-gravity oils are to be stored, the steel tank should be provided with explosion doors to relieve the tank of excessive pressures which might cause its disruption in case of fire or explosion within. This precaution is particularly important in regions where electrical storms are common.



(*After C. P. Bowie in U. S. B. Mines Bull.* 155).

Outer ring and supporting posts. Inner ring and supporting posts.

FIG. 300.—Structural details of roof supports for 55,000-barrel steel tank.

It is obviously impossible to design explosion doors of sufficient area to relieve adequately the pressure developed in a violent explosion where a large volume of gas is mixed with just the proper proportion of air to form an explosive mixture. Such a condition, however, rarely exists within a tank in which oil is stored, and it is thought that eight explosion doors arranged at equal intervals about the roof, each having an area of approximately 9 sq. ft., will relieve the tank from serious injury in most cases.

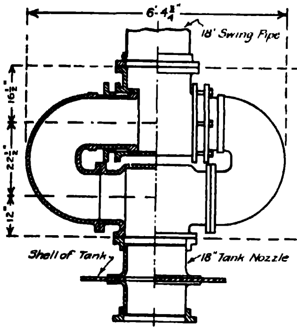
A good type of explosion door is of disc form, held in position over a flanged hatch in the roof by means of vertical guides.[7] The disc has a flanged edge and develops a gas-tight joint with the hatch flange with the aid of a water seal (see sketch, Fig. 302). In case of an explosion, the disc is raised from the flange on which it rests by the force of the compressed gases and, after the release of pressure, again falls into position, the guides serving to keep it in position over the hatch opening.

Vacuum Relief Valves.—The tank should also be provided with a vacuum relief valve to permit air to enter when oil is being withdrawn. This consists of an ordinary swing check valve, so mounted that the check will swing inward. The valve is connected by means of suitable pipe fittings to a flange in the roof of the tank. Admission of air to the valve should be through an ell, the open end of which is screened and turned downward over the edge of the tank roof.

Tank Metals.—The steel ordinarily used in tank construction should conform to the "Standard Specifications" prescribed by the American Society for Testing

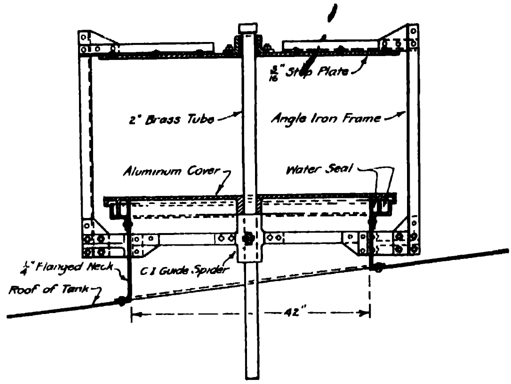
Materials for structural steel, and may be made by either the Bessemer or open-hearth processes. It should contain not to exceed .06 per cent of phosphorous and not more than .045 per cent of sulphur. The tensile strength averages about 55,000 lb. per square inch and the elastic limit is about half of this amount.

One manufacturer of bolted tanks uses a steel containing from .2 to .25 per cent of copper, which is superior in its resistance to corrosion in comparison with ordinary mild structural steel in which copper is not present. The corrosive properties of tank materials, particularly the bottom plates, which are subjected to contact with saline water derived from the oil, would appear to be worthy of serious consideration.



(*After C P. Bowie, U S. B. Mines Bull* 155).

FIG. 301.—Swivel joint for swing pipe, 55,000-bbl. steel oil storage tank.



(*After C P Bowie, U. S. B Mines Bull.* 155).

FIG. 302.—Explosion hatch for 35,000-bbl. steel oil-storage tank.

Welding of tank plates with the aid of the oxyacetylene torch or one or another of the electric welding methods offers interesting possibilities as a substitute for riveting in the construction of steel oil tanks. The general use of the oxyacetylene torch in all classes of sheet metal work and successful application of the fusion arc-welding and spot-welding processes in steel ship construction during the war are regarded as sufficient proof that these methods are feasible from every point of view. It is already common practice to weld the plates of small tanks, particularly those in which very light distillates and condensates—such as casing head gasoline—are to be stored.

The great advantage of welded-joint construction is that the tank may be made secure against leakage of gas. Loss of oil vapor as a result of "breathing" of the tank roof through expansion and contraction of gases, a process so destructive to calked and riveted joints, may be practically eliminated by applying the welding process to the top ring and roof plates. The welding process, if carefully performed, produces a joint as strong as the riveted joint and under favorable conditions the work may be more rapidly accomplished. Welding is probably cheaper than riveting in many cases.

It is doubtful whether the present electric welding methods could compete on this class of work with the oxyacetylene torch from the standpoint of cost. Furthermore, oxyacetylene apparatus is usually available in the oil fields, while the electrical apparatus is not; and it is easier to secure men skilled in the use of the gas-welding equipment. It seems probable that further development in the application of welding methods to oil field work will, within the next few years, demonstrate the superiority of this type of construction in the building of oil storage tanks.

Wooden Roofs for Steel Tanks.—For the storage of heavy oils where evaporation losses are not a serious factor, steel tanks are frequently equipped with low, conical

wooden roofs instead of the steel type of roof already described. In such cases the roof supports are also of wood. Footing blocks 2 by 8 in. and 2 or 3 ft. long, placed on the bottom of the tank, support 6- by 6-in. posts arranged in two or more concentric circles. Girders, 6 by 12 in. in cross-section, span the spaces between the posts in each circle and provide supports for 2- by 8-in. rafters placed radially. The rafters are covered with 1- by 6-in. or 1- by 12-in. wooden sheathing, generally planed to secure fairly tight joints, but occasionally laid on rough. The posts in each successive ring are tied together by means of diagonally placed 1- by 6-in. braces. In order to prevent leakage of water from without and to reduce evaporation losses as far as possible from oil stored within the tank, the wooden roof is generally covered with roofing paper (sometimes with pebble finish), with sheet iron, or with an especially prepared asbestos roofing.

Among the disadvantages of this type of roof, aside from the obvious difficulty of making it secure against leakage of gas, may be mentioned the increased fire risk and the damage which such a roof frequently suffers in regions where heavy wind storms are prevalent.

Methods of Reducing Evaporation Losses in Steel Tanks.—A study of the problem of reducing evaporation losses of oil stored in steel tanks has led to the development of a number of different methods of controlling temperatures within the tank and of preventing the escape of vapors. Much may be accomplished in the way of reducing temperatures of stored oil by painting the tanks with heat-reflecting colors. Still better results are obtained by lagging the outside of the tank shell with terra cotta tile or wooden sheathing. Sprinkling the sides and top with water has also produced beneficial results, and the idea of cooling with water has been carried still further in the development of the water-top tank. In the latter case, the tank is equipped with a flat roof a few inches below the level of the top of the cylindrical shell, and the depression thus formed on top of the tank is filled with water, which aids materially in reducing temperatures within. Burying the tank in an excavation so that the roof is level with or below the ground surface has been suggested and would undoubtedly be successful in reducing temperatures. However, the excavation would be costly, the tank would be short-lived, and earth pressure against the tank shell would complicate the design. A plan for collecting hydrocarbon vapor escaping from the oil and using it to equalize pressure conditions in a group of tanks has also been successfully applied.

Experiments conducted by the U. S. Bureau of Mines[16] have shown that the temperature of oil stored in white-painted tanks is from 5 to 10°F. lower than oil stored in black-painted tanks, other conditions being identical. Red paint is but little better than black paint in its heat-reflecting properties, there being a difference of only 2°F. Aluminum paint and tin plate have better radiating properties than white paint, but are scarcely practical for use in tank protection. An oil-stained surface is a better heat absorber than an ordinary black-painted surface.

Tanks "lagged" or "shedded" with an outer protection of wood, terra cotta tile or other material, which makes it possible to surround the tank with an air space or a layer of other non-conducting material, are particularly efficient gasoline con-

servers. Tile protection has been effectively used on tanks in which especially volatile products are to be stored, generally in and about refineries. This material is expensive, however, and on account of its weight, cannot be used economically on large tanks as a roofing material. Wooden sheathing has the advantage that it may be applied to the roof as well as to the cylindrical shell of the tank, and if a layer of sawdust or roofing paper is placed between the sheathing and the metal, wood is probably as effective in its non-conducting properties as tile. Wooden sheathing undoubtedly adds to the fire risk, however, while tile is an added protection against fire. One refining company reports the erection of corrugated asbestos-coated steel "jackets" about five 65,000-bbl. storage tanks. These structures enclose the tanks completely, leaving a dead-air space between the jacket and the walls and roof of the tank. For each jacket 5 tons of steel and 3,000 sq. yd. of asbestos sheathing are required, and it is claimed that the saving in evaporation losses will soon repay the additional cost.

Water cooling of oil storage tanks is probably as effective as any other method in reducing evaporation losses. Water cooling devices take the form of revolving sprinklers mounted on the peak of the tank roof, or of actual submergence of the roof under water.[7] In the former case, cooling of the tank is effected by evaporation of water spread in a thin film over the entire roof and shell of the tank, while in the case of the water-top tank, evaporation losses are reduced not only by the maintenance of lower temperatures, but also by absolutely preventing leakage of gas through the tank roof. The cooling effect in the latter case may be enhanced by circulating the water used through a louvre tower or cooling pond with the aid of a pump. Neither of these water-cooling devices have found extensive use, though they are occasionally met with in and about refineries and casing head gasoline plants for the storage of light distillates.

A plan has been proposed, and even put into practice in several instances, which involves connecting all of the storage tanks in a group by a system of piping, with a large gas storage tank or gasometer, so constructed as to equalize gas pressures throughout all the tanks of the group. Every effort is made to keep the tank roofs gas-tight; and such adjustments in gas volume as may be necessary to offset variations in level of the oil in the tanks are effected by discharging into or drawing gas from the gas storage system. Oil in the tanks is thus always blanketed by a saturated oil vapor, and gas expelled from the tanks on expansion of the oil, or during the filling of a tank, is drawn back again when the oil contracts in volume or when the tank is emptied. Under these conditions, when the air in the system becomes saturated with vapor, no further evaporation of the oil should occur.

Study of evaporation losses in oil in storage during recent years has led to considerable improvement in the development of vapor-tight tankage. Recent designs embody the use of improved types of joints, and pressure and vacuum relief valves and vapor-tight hatches.[14]

REINFORCED-CONCRETE TANKS

The use of reinforced concrete in the construction of tanks for oil storage was first given serious attention in the United States during the years of the World War, when sheet metal for steel tankage became almost unobtainable. The enforced use of concrete during this period served to demonstrate its practicability and engaged the interest of many engineers in the further development of this type of tank. Some engineers consider it a formidable rival of the conventional steel tank.

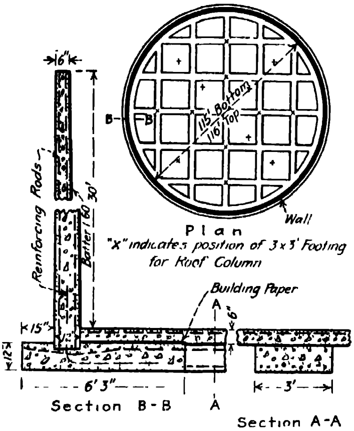
The reinforced-concrete tank appears to have certain definite advantages over the steel tank. Such tanks are not subject to corrosion and therefore require no protection against rust-forming agents, whether above or below ground. The material is not subjected to electrolysis. Reinforced-concrete tanks can be designed to better advantage in resisting external pressure due to earth pressure or to the hydrostatic head in soils developed by ground waters. Concrete tanks can be readily constructed in any unusual shape that may be imposed by the terrain or by other physical plant in the vicinity of the location selected. The low conductivity of the material insulates oil stored in such a tank against extreme temperature changes, thus retarding evaporation losses in summer and making the pumping of oil easier in winter. Aside from the matter of more uniform temperatures, evaporation losses can be further reduced since a concrete roof can be made practically gas-tight, whereas a steel roof often is not. As a result of lower oil temperatures, lower heat conductivity, and smaller gas leakage, and also because the material does not attract lightning as does steel, the fire risks on oil stored in concrete tanks are materially lessened. Furthermore, the materials used in concrete construction are often obtainable locally, thus eliminating delays arising in the shipment of fabricated steel tankage from a distant supply center. Maintenance and repairs, such as painting and calking, often important items in steel tankage, are of course unnecessary in the case of concrete. A concrete tank probably has a longer life than a steel tank.

Among the important disadvantages that may be mentioned in comparing the reinforced-concrete type of tank with the steel tank, are its lack of portability and greater first cost. The steel tank may be "cut down" and moved to a new location and reassembled, while the concrete tank is a fixture and has little or no salvage value in case it survives the need for which it was constructed. If steel tankage is readily available, it can be more rapidly assembled and placed in service than concrete storage can be constructed.

Practice in the design and construction of reinforced-concrete tanks has not as yet established any particular form or type as standard. Most tanks so far constructed are of the cylindrical, vertical-walled type, but some are rectangular with sloping walls, after the design of the earlier type of concrete reservoirs described in a later section. The roof and bottom are generally of flat reinforced-concrete slab construction, but occasionally the roof may be arched upward, and in the case of a tank buried below ground level there are certain advantages to be secured in designing the bottom as an inverted arch, giving increased storage capacity and more effectively resisting upward earth and hydrostatic pressures. Practice differs also in the design of the roof supports.

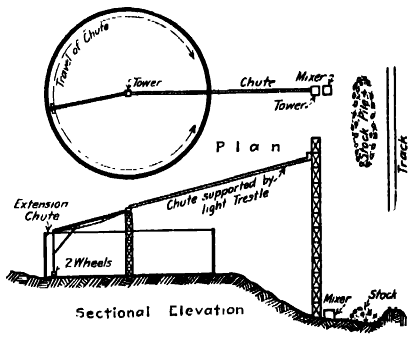
Concrete tanks are preferably placed below ground in order to secure the advantages of lower oil temperatures, smaller evaporation losses and better protection against fire. The earth in this case may also give support to the walls, giving somewhat greater security in resisting oil pressure. The excavation cost is an added expense, however, which must be balanced against the advantages of underground location.

Accepted practice appears to favor the circular form of tank, which is simpler in design and is less susceptible to tensile cracks resulting from stress and variable temperatures. One successful designer[2] prefers to



(*After R. C. Hardman in Eng News-Record*)

FIG. 303.—Structural details and general plan of 55,000-bbl. reinforced concrete oil tank.



(*After R. C. Hardman in Eng. News-Record*).

FIG. 304.—Illustrating manner of transporting concrete from mixing plant, 55,000-bbl. concrete oil tank.

limit the size to capacities not exceeding 7,200 bbl. (300,000 gal.), since it is difficult to construct larger tanks without interruption in the continuity of operations, so essential to the securing of a uniform structure without construction joints. However, this would seem to depend largely upon the resources in plant and personnel of the contractor undertaking the work. Many larger tanks have been successfully constructed (see Figs. 303 and 304).

Impermeability of concrete against oil seepage and absorption is best secured by taking adequate precautions against the formation of cracks, and by selecting materials to produce a mixture of maximum density and minimum porosity. Fuller and Thompson* have suggested a method of determining the proper proportions of various sized ingredients to accomplish this. A mixture of 1 part of cement with 3 parts of sand, 1½ parts of ½-in. crushed rock and 2½ parts of 1-in. crushed rock, according to the principles established by Fuller and Thompson, should theoretically give a mixture of maximum density. This mix has been successfully used in the bottom linings of some California reservoirs where the concrete could be thoroughly

* The laws of proportioning concrete, *Trans.*, Am. Soc. Civil Eng., vol. 59, p. 67.

tamped. Most designers prefer a 1:1½:3 concrete, in which the coarse aggregate will pass a 1-in. ring. The American Concrete Institute in its specifications for reinforced-concrete oil tanks recommends a concrete of these proportions. Occasionally, larger sizes of crushed rock in the coarse aggregate will be permitted, 2 in. and even 4 in. in some cases, but the desirability of using such coarse material is questionable. Hydrated lime to the extent of 10 per cent of the cement used is sometimes added to the mix, rendering the concrete more plastic, easier to work around the reinforcement and hastening the "set." It is claimed by some engineers that the use of so large an amount of hydrated lime is detrimental to the concrete, causing the formation of hair cracks, or even scaling of the outer coating of mortar; but the practice is defended by some of our ablest designers.

Care should be taken to avoid an excess of water in mixing the concrete, as its strength is seriously affected thereby and there is a tendency, if a surplus is used, for the coarse aggregate to separate from the mortar during its transportation from the mixer to the forms. Sufficient water should be used, however, to produce a plastic, workable mixture which will flow sluggishly and which can be worked into the forms and around the reinforcement without leaving voids.

It has been shown in experimental tests conducted by the U. S. Bureau of Standards[13] that properly proportioned and prepared concrete is practically impervious to all but the lighter oils. Seepage and absorption losses through concrete linings are found to be negligible for oils below 35° in Baumé gravity. Losses of kerosene and gasoline in concrete containers, however, may be appreciable; and this type of storage is not to be recommended for the lighter crudes and distillates unless the concrete surfaces exposed to the oil are given an oil-proofing treatment. For this purpose, silicate of soda (water glass) of 40°Bé. density (Baumé scale for liquids heavier than water) diluted with from 1 to 3 parts of water and applied in three coats at 24-hr. intervals, has been found effective, though it is not a permanent coating. Spar varnish thinned with 20 per cent of "volatile mineral spirits" (a petroleum distillate intermediate between commercial kerosene and gasoline), and applied under a pressure of 60 lb. per square inch with a paint gun, is probably more effective. This preparation is also applied in three coats at 24-hr. intervals using approximately 1 gal. to each 200 sq. ft. in each coat.[12] For oil-proofing concrete fuel oil tanks, the Bureau of Yards and Docks of the U. S. Navy Department specifies two coats of spar varnish or glutrin preceded by one coat of 7½ per cent solution of calcium fluo-silicate (about 1 gal. of the latter to each 100 sq. ft.).

Petroleum apparently has no detrimental effect upon concrete once it has properly set and hardened; but some engineers do not consider it good practice to place oil in contact with concrete until it is 6 weeks old. If necessary to place the tank in service earlier than this, it is suggested that the inner walls be given a protective coating of one or another of the oil-proofing compounds mentioned above, so that hardening of the concrete may proceed without danger of its being deprived of its moisture content. The necessity for this practice is questioned by some authorities.

Design of Reinforced-concrete Tanks.—The tank must be designed to withstand not only the stresses imposed by the oil stored in it, but also those due to its own dead weight and to external pressures—such as earth pressure and hydrostatic ground water pressure against walls and bottom, the weight of the earth covering as well as possible snow and other live loads on the roof. Concentration of loads on walls and columns should be avoided as far as possible.

In circumferential walls, the thickness of the concrete should be based on a tensile strength of not more than 150 lb. per square inch. This allows for a small factor of safety, the ultimate strength being generally over 200 lb. per square inch. It is difficult to place and compact concrete effectively in a deep and narrow wall form. For this reason, even though unnecessary from the standpoint of design, a minimum

thickness of 8 in. at the top and 10 in. at the bottom is recommended for all walls.

For steel reinforcing, which preferably consists of round, deformed bars of medium steel, a maximum working stress of 10,000 lb. per square inch above ground, or 12,000 lb. per square inch below ground, should be allowed.[1] While the steel naturally carries a part of the stress imposed, the walls should be designed as though the concrete were to carry the full load. If concrete in the walls is stressed beyond its ultimate strength, the walls will not fail because the load will be transferred to the steel reinforcement; but the tank will nevertheless fail to serve the purpose for which it was built, since cracks will develop and the structure will no longer be secure against leakage. Reinforcement in the walls should be placed circumferentially. The floor and roof should be reinforced both circumferentially and radially to provide against temperature and other stresses. Reinforcement laps should not be less than 40 diameters at joints.

Ordinarily, when the tank is full, the oil pressure on the inside is about twice as large as the active earth pressure on the outside. External hydrostatic pressure due to accumulated ground water back of the walls probably seldom exceeds 50 per cent of the theoretically possible hydrostatic pressure, but it seems preferable to assume that the full hydrostatic head may be exerted and allow the difference as a safety factor. It is apparent in the case of a tank buried in the earth that the walls may receive an unbalanced load from either the inside or the outside, so theoretically they should be reinforced on both the inner and outer faces.

Roof columns in structures of this type do not present any unusual problems beyond those encountered in ordinary reinforced-concrete construction. They should, of course, be of ample cross-section to support the roof load, which can be readily calculated. The column footings should be monolithically constructed with the tank bottom, and should be of sufficient size to distribute the load adequately. The tops of the columns and walls should be tied to the roof by the reinforcing bars.

Expansion joints are necessary when the structure is likely to be subjected to abnormal temperature stresses. They are particularly necessary where the vertical walls make contact with the roof, unless the reinforcing in the walls is designed to take care of any bending moment that may occur. In tanks placed above ground where elongation of the walls may occur as a result of both temperature and pressure, it may be necessary to provide an expansion joint at the base of the walls where they connect with the bottom slab. This may be accomplished by building the walls on a suitable footing which is independent of the floor resting on it. Building paper or a strip of crimped metal plate may be inserted between the slab and wall-footing to reduce or prevent leakage at this point.

If the foundations under the tank are partly filled and there is any possibility of settling, the bottom slab may be protected to some extent against cracking by reinforcing it with a rectangular grid of concrete, cast monolithically with the bottom slab. This construction was adopted in the case of a 55,000-bbl. concrete tank built for the U. S. government in the Panama Canal Zone[12] (see Fig. 303).

Flanges for suction piping, drains, manholes, gage hatches, etc., must be placed in the walls and roof during the depositing of the concrete and every precaution taken to prevent leakage of oil around such castings. Companion flanges should be used, one on either side of the wall, with a connecting nipple cast into the wall. Spaces of about 1½ in. should be left between the flanges and the concrete, these spaces to be later calked with litharge and glycerin or other suitable oil-proofing material. It is also desirable to attach a ring to the nipple at its center, about 2 in. larger in diameter than the pipe. This ring is cast in the center of the wall and acts as a dam around the nipple, effective in reducing oil seepage which is apt to occur at this point.

Construction begins with the excavation and preparation of the foundations, which is adequately discussed elsewhere in this chapter in connection with foundations for steel tanks and excavations for concrete-lined reservoirs.

Erection of the forms for the concrete is next in order. The forms should be of good material, planed to uniform thickness and width and, for walls, preferably tongued and grooved. The material should be carefully joined to insure smooth surfaces, and should be well braced so that no distortion during or subsequent to placing of the concrete is possible. In the case of circular walls, forms may be held in place by circumferential bands. The use of bolts or wires through the concrete to hold the reinforcing material in position, or to hold the inner and outer forms together, should be prohibited. The forms should be oiled or thoroughly wetted immediately before placing the concrete in them.

The difficulty of placing and compacting concrete in deep, narrow wall forms may be avoided by the use of standardized forms built in movable sections that may be raised at 6-ft. intervals as the work proceeds; or the inside forms may be built complete, the inside studs and braces placed and the inside lagging nailed on strip by strip, in advance of the pouring operations. In the latter case, the concrete can be deposited in thin layers and carefully compacted and inspected as each layer is poured. The process is continuous, necessitating no interruption in raising the forms. However, the forms should not be removed before the concrete has had time to properly set and harden, otherwise deflection or actual failure of the work may result. Column and wall forms should remain undisturbed for at least 48 hr. after the concrete is poured, and roof forms at least 7 days.

The reinforcing material should be accurately bent or curved to templates, carefully placed and rigidly supported in their designed positions.

The concrete mixing plant should be of adequate size and capable of continuous mixing so that no interruptions in the pouring operations may occur. Conveyance of the mixed concrete from the mixer to its place in the work should be by inclined chute if possible. Fig. 304 illustrates a convenient arrangement by means of which placing of the concrete may be accomplished with a minimum of labor and time.[12] A semi-circular metal chute of somewhat greater length than the tank radius is carried at its lower end by a light ladder mounted on two wheels placed to travel circumferentially, and its upper end is supported by a light tower built at the center of the tank. The chute dumps directly into the circular wall forms, and the ladder construction makes it possible to carry the chute at any desired elevation. This revolving chute is fed from a hoisting tower by means of a second stationary chute.

Depositing of the concrete begins with the pouring of the floor and column footings. In placing concrete in floors, it should not be allowed to stand with exposed vertical faces where the work is temporarily discontinued. The column footings are poured as a part of the floor. Concrete in the walls should be placed in layers of 12 in. or more around the entire circumference, so that a monolithic structure will result. The piling up of concrete in the forms in such a manner as to permit escape of mortar from the coarser aggregates should not be permitted. Pouring of the roof columns may follow construction of the walls, or may proceed simultaneously therewith. A 6-hr. interval should be allowed between completion of the columns and pouring of the roof slabs. In all other parts of the work, no break of more than 45 min. should occur during the pouring of any part of the structure. If the placing of concrete is unavoidably interrupted, the previous surface should be roughened, washed clean and luted with a 1:1 mortar immediately before resuming pouring operations.

The floor and roof should be brought to grade with a straight edge or strike board and troweled to a smooth surface as soon as possible after the concrete is deposited. As soon as the wall, column and roof forms are removed, any voids which

may appear as a result of improper placing and compacting of the concrete are carefully roughened, cleaned, moistened, filled with a 1:1½ mortar and troweled. Some engineers recommend that all exterior walls be painted with asphalt as soon as the wall forms are removed.

After the forms and all waste material have been cleared away, the tank may be equipped with its swing pipe, ladders, manhole and vent covers, and is ready for service as soon as sufficient time has elapsed for the concrete to harden properly, unless it is considered necessary to oil-proof the interior surface as previously described.

CONCRETE-LINED RESERVOIRS

There is little real distinction which exists between the reinforced-concrete type of tank that has just been described, and the so-called concrete-lined reservoir. The term "tank" is usually applied to containers corresponding in capacity to the ordinary sizes of steel tanks, while the "reservoir," in the ordinary meaning attached to the word, is a structure of much greater capacity. The chief distinction, perhaps, is one of design, the tank being designed with walls—generally vertical—of sufficient thickness to withstand all stresses due to either internal or external loads, without outside support; while the concrete used in reservoirs is usually regarded primarily as an impervious lining for the earthen embankments. In the latter case the embankments support the concrete, which is relatively thin, and provided with just enough reinforcement to prevent cracking. The walls of the reservoir are generally sloping in order to give greater stability to the concrete and embankments under the weight imposed by the oil. The concrete tank may be, as far as the design is concerned, constructed above ground, while the reservoir must always be below the ground surface.

General Features of Concrete-lined Reservoirs.—The concrete-lined reservoir for the storage of petroleum, as developed and applied chiefly in California, consists usually of a circular or elliptical embankment having sloping sides, from 20 to 26 ft. in height, the entire inner slope of the embankment and the level area enclosed by it being paved with a layer of concrete, suitably reinforced, and from 2 to 4 in. in thickness. Diameters are occasionally as great as 500 ft., the paved area being in excess of 310,000 sq. ft. Capacities commonly range from 500,000 to 1,000,000 bbl. One California reservoir is elliptical in form, 785 ft. long, 467 ft. wide and 23 ft. deep. It covers 9¼ acres of ground and provides storage for 1,045,500 bbl. of crude petroleum. One recently constructed (1923) reservoir has a capacity of 2,500,000 bbl. The embankment which encloses the reservoir is partly developed by excavation of the depression forming the bottom, and is partly built up of loose material derived from the excavation. The bottom of the reservoir is thus below the original ground level surface, while the top of the embankment is some distance above.

A low conical roof is provided, supported partly on posts resting on the floor of the reservoir and partly on sills placed in the top of the embankment. Drains and gutters of adequate proportions conduct rainfall from the roof and over the sides of the embankment. Oil is led into and out of the reservoir through metal pipes of large size, penetrating the embankment at about the level of the reservoir bottom. On the inside of the reservoir these pipes terminate in swing pipes by means of which oil may be drained from any desired level. Stairways are provided both on the inner and outer slopes of the embankment for ready access. Winches controlling the swing pipes, and hatches for ventilation and gaging purposes, are placed on the roof.

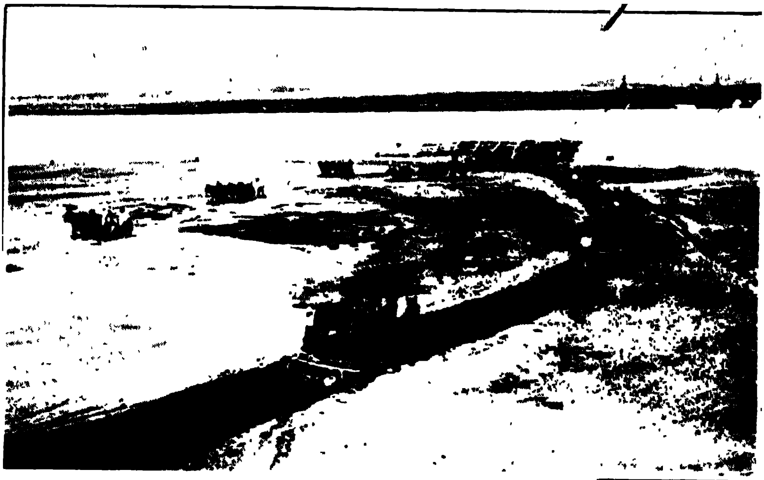
Reinforced-concrete Reservoir Construction. *Drainage.*—The character of the soil is particularly important in the selection of a reservoir site, it being essential that water be excluded as far as possible from the embankments. Concrete reservoirs for the storage of oil are not designed to withstand more than moderate earth pressure and hydrostatic pressure from without, and consequently no site should be selected which does not lend itself to thorough drainage. Water under pressure back of the walls or under the bottom of the concrete lining may cause the concrete to crack when the reservoir is empty. Furthermore, water flowing through the embankment may wash the earth away, leaving the concrete without adequate support. If porous, sandy strata or gravel are encountered during the progress of the excavation, they should be removed to a depth of several feet below the subgrade, and the excavation then refilled to grade with carefully tamped clay or other impervious material. The use of drain pipes in the embankments has been proposed, but will not be necessary if the site is chosen with due regard to the securing of good natural drainage.

Earthwork.[7]—The site selected for the reservoir must first be cleared of all vegetation, an ordinary road grader being employed to loosen the earth down to the grass roots, after trees, stumps, large roots and brush have been removed. Plows then loosen the underlying material which is removed with scrapers, alternately plowing and scraping, layer by layer, until the subgrade is reached. The bottom is plowed to a depth of about 1 ft. below the finished grade, carefully leveled by harrowing or by dragging heavy planks over the loosened material, then sprinkled with water and rolled with a steam roller. The floor of the reservoir is given a slight slope toward a depression called the "swing pit," near one side of the bottom, into which the inlet and outlet pipes are led.

The walls are either excavated from material in place, or must be built up with earth excavated from the bottom or from borrow pits in the vicinity. If the material is in place and earth must be excavated from the side slopes, a narrow cut is first made to final depth around the outer edge, leaving four inclines at quarter points on the circumference for access to the bottom of the reservoir. The material on the slopes is then removed by plowing and scraping, until the bottom of the cut is reached, care being taken to maintain the desired slope of the embankment. The final slope is then plowed below subgrade, sprinkled and compacted with the aid of a petrolithic roller.

If the embankment must be built of loose material, excavated from the bottom of the reservoir or from near-by borrow pits, scrapers will be used in placing it. The embankment is built up in horizontal layers, each layer being moistened with water and compacted with the petrolithic roller before the next successive layer is placed. The work of placing the material and compacting it can proceed simultaneously, the embankment being divided into sections and the two processes of rolling and filling

on the different sections are alternated. The top and sides of the embankment are filled and rolled to form a surface several inches above the proposed finished slope, and the material is subsequently scraped off to form a well-compacted surface. Small boards placed radially in the embankment, flush with the desired finished surface, may be used as guides in trimming the slope. Trimming of the slope between the guides is conveniently accomplished by the use of a screed board which spans the interval between slope guides. The outside slope of the embankment is thoroughly sprinkled with oil to waterproof the material and prevent the growth of vegetation. The slope should be re oiled two or three times each year if this is to be effectively accomplished.



(*After C. P. Bowie in U. S. B. Mines Bull* 155).
FIG. 305.—Excavating for large oil storage reservoir.

When the embankment is completed and the bottom and slopes are compacted and dressed to final grade, excavations are then made for the concrete pillar footings which support the roof posts. An excavation in the floor 4 ft. wide and 4 in. deep is also made at the foot of the inner slope around the entire reservoir, the function of which is to provide a footing for the slope paving.

Roofing.—Construction of the roof and roof supports should preferably precede the pouring of the concrete lining.[7] Since no expansion joints are provided in the concrete paving, it is advisable to take every precaution against the development of shrinkage or expansion cracks, which may result from extreme variations in temperature. The roof serves to maintain more uniform temperature conditions within the reservoir, resulting in a denser, better cured and more homogeneous concrete.

The post footings must first be poured in the form illustrated in Fig. 306. A metal pin is set in the center of the concrete footing, projecting 3 in. above its upper surface. The purpose of this dowel pin is to hold the post in position, a hole of suitable size and depth being bored in the center of the bottom of each post to contain the part of the pin which projects above the concrete footing.

The posts supporting the roof are 6 by 6 in. in cross-section and support on their upper ends, 4- by 14-in. knee-braced girders. The posts being arranged at intervals around the circumference of concentric circles (see Fig. 306) the girders become chords of these circles and provide points of support for the 2- by 8-in. rafters which are placed along radial lines of the same circles. The outer row of rafters rests on

2- by 12-in. redwood mud sills placed near the inner edge of the top of the embankment. The roof sheathing is of 1- by 8-in. material, surfaced on one side, of assorted lengths to break joints, and is covered with a layer of three-ply, graveled, asphaltic roofing paper. An asbestos-coated metallic sheathing has been successfully used in recent installations, instead of wooden sheathing and roofing paper. The outer 10 ft. of sheathing, around the circumference of the reservoir, is not placed in position until after the concrete for the slopes has been poured.

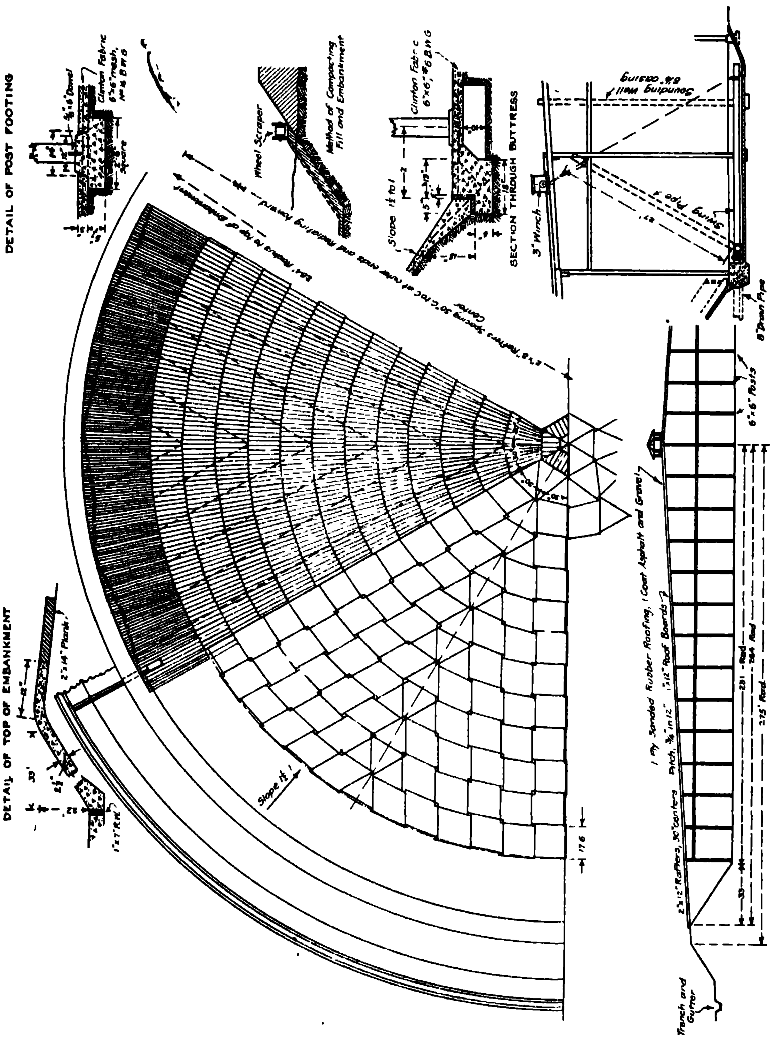
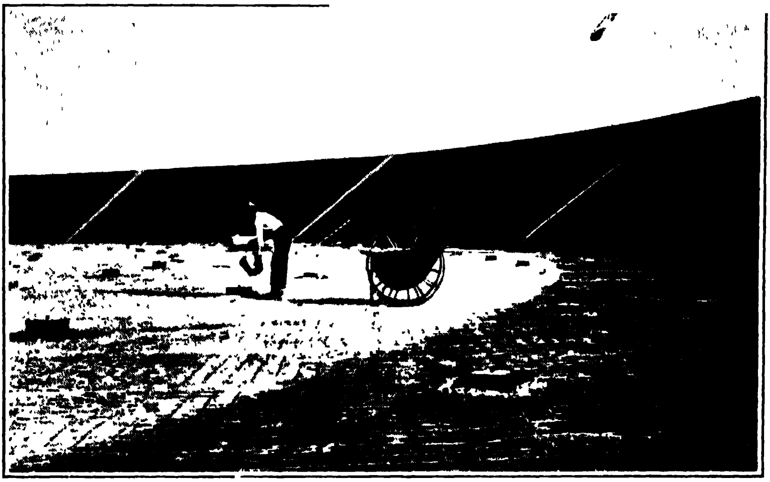


FIG. 306.—Plans for a 750,000-bbl. oil reservoir of earth, lined with reinforced concrete. (*After C. P. Bowie and Bacon and Hamor*).

Concrete Surfacing.—The principal objective in the design and construction of the concrete reservoir lining is to provide a continuous layer of concrete, free from shrinkage or expansion cracks and sufficiently thick and dense to prevent the seepage of oil through it. If properly reinforced, this may be accomplished on suitably prepared foundations with a lining of concrete ranging from 4 in. in thickness on

the bottom to 2 or 3 in. on the upper slopes of the embankment. The pavement is monolithic, no expansion joints being provided.

The concrete is mixed in one or more mechanical mixers located just outside of or on the top of the reservoir embankment, and is carried to its position in the work by suitably placed elevators, inclined chutes and concrete buggies. For convenience, the concrete may be transported to various points on the top of the embankment by means of a car operating on a track which encircles the rim. From this car the material may be discharged into inclined chutes on the inner slope, which carry it to its position in the embankment or to concrete buggies which distribute it over the floor (see Fig. 307).



(*After C. P. Bowie in U. S. B. Mines Bull.* 155).

FIG. 307.—Illustrating manner of preparing floor slab and roof column footings in a large oil storage reservoir.

The reinforcing material consists of 4- by 4-in. or of 6- by 6-in. mesh of No. 6 gage wire, and is spread over the area to be surfaced before any concrete is poured. The reinforcement is in strips usually about 7 ft. wide and 240 ft. long, and is laid—circumferentially on the slopes—over the entire inner surface of the sides and bottom. The strips are lapped one mesh at the joints and are securely wired together. As the concrete is poured, the reinforcement is pulled up until it occupies the approximate center of the concrete slab.

In concreting the floor, work begins at the swing pit and proceeds until the entire bottom is poured. Header boards are placed 12 ft. apart and the 12-ft. strips are poured alternately, tamped and given a trowel finish. On the slopes, which are also laid in 12-ft. strips, the placing of the concrete begins at the top and proceeds down the embankment until the bottom is reached. A stiffer mix is used on the slopes than is used on the bottom, since thin concrete will tend to flow down the embankment to some extent before it takes its final set. A concrete mixture that is too thick to flow readily on the slopes will not take a very smooth finish, and some specifications call for a thin 1:2 grout surface spread with a trowel on the concreted slopes.

The suction and inlet pipes and water drains are imbedded in a slab of concrete at the point where they pass through the embankment. Precautions are taken to have the concrete slab of adequate thickness to prevent leakage of oil at this point.

This and the junction of the slopes with the floor constitute the weak points in the ordinary type of reservoir. The latter point is strengthened against possible expansion cracks by thickening the concrete flooring to 7 in. for a width of 4 ft. around the entire periphery of the bottom.

Cost of large concrete-lined oil storage reservoirs, of the type described above, at Bakersfield, Cal., in 1914, ranged from 10 to 13 cts. per barrel of capacity.[7] On a basis of 11 cts., the cost would be distributed approximately as follows: cost of earthwork, 3.5 cts.; cost of roof, 3 cts.; cost of concrete lining, 4.5 cts.; total cost, 11 cts.

The following unit costs, based on actual performance in the case of two 750,000-bbl. reservoirs, are of interest:*

Earthwork:	
Excavating for embankment, per yard	$ .220
Lining inner slopes with selected material, per yard	.510
Finishing floor, per square foot	.005
Excavating for pier footings, trenches, etc., per yard	.700
Trimming slopes, per square foot	.120
Roof:	
Hauling lumber from railroad (½ mile), per M	1.190
Framing lumber for roof, per M	1 600
Erecting roof, per M	3.800
Sawing sheathing, per M	1 350
Laying roofing paper, per square	.120
Hauling roofing gravel from railroad (½ mile), per ton	.250
Placing asphalt and gravel coating, per square	.320
Concrete lining:	
Hauling cement from railroad (½ mile), per ton	.540
Hauling sand from creek bed (2 miles), per yard	.860
Hauling rock from railroad (½ mile), per yard	.500
Laying reinforcing metal on slopes, per square	.160
Laying reinforcing metal on floor, per square	.080
Pouring concrete piers, per yard	4.630
Pouring concrete floor, per yard	2 510
Pouring concrete on slopes, per yard	3 460

Use of the Cement Gun in Reservoir and Tank Construction.—It has been demonstrated on a large scale in many instances that cement-sand-water mixtures may be successfully used in the building of tanks and in the lining of reservoirs with the aid of the cement gun, a device which applies the concrete as a spray, using compressed air as the spraying agent. Mixtures containing as much as 3 parts of sand to 1 part of cement can be successfully used in this way. The resulting concrete is hard, dense, impermeable to water and oil, and is as strong as concrete construction of the ordinary sort if properly applied.

* These figures are based on the following wage rates per day of 9 hr.: laborers, $2.50; carpenters, $3.50; concrete laborers, $2.75; concrete finishers, $4.50; foremen, $6. The soil on the reservoir site was a light sandy clay.

"Gunite" walls and slabs as thick as 6 in. have been successfully constructed, but the method finds its greatest usefulness in the lining of reservoirs and in oil-proofing or waterproofing porous materials. Vertical walls may be constructed by this method without the use of forms. The steel reinforcement is first erected in the form of the structure desired, with the required amount of spiral reinforcing material (with hooked ends) securely fastened in place. Over this frame is placed a heavy wire netting of triangular mesh which serves chiefly to hold the concrete in place while setting, but also forms additional reinforcement. When this steel structure is erected, heavy canvas or ducking is stretched over the outside and upon this (working from the interior) a layer of concrete from 1 to 1½ in. in thickness is applied by means of the cement gun. When this layer has set for a short time, the canvas is removed and additional layers of concrete are applied both from the interior and exterior. In this way, the walls are built up to the desired thickness, and since each layer is applied before the previous one has set, the result is a thoroughly homogeneous concrete mass. The roof is built in the same manner. All outer surfaces are given a float finish. A reservoir constructed by the Anaconda Copper Company in 1917 is lined entirely with gunite and without the use of any stone. The bottom of this reservoir is 6 in. thick and is doubly reinforced with triangular wire mesh.

The cement gun would apparently offer a convenient and inexpensive means of constructing a light concrete roof over an oil reservoir or tank, the main walls and bottom of which perhaps can be more economically constructed by other methods. Such a roof could be made gas-tight and

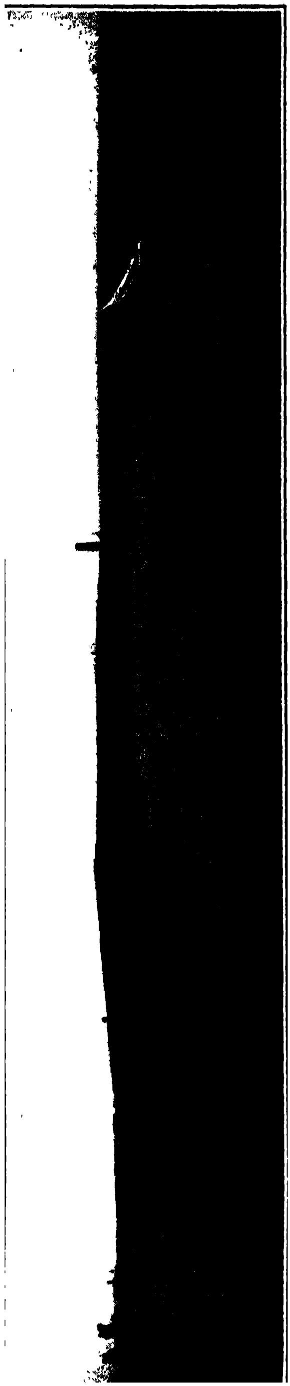


Fig. 308.—General view of large oil storage reservoir during construction.

fireproof, and would have a further advantage over the wooden or steel type of roof in assuring lower oil temperatures.

Earthen Reservoirs

It occasionally happens that the "bringing in" of an unexpectedly prolific well creates a demand for oil storage facilities that the operator is quite unable to meet by the usual means. Perhaps it is a pioneer well in a new field, that comes in as a "gusher," out of control, and a large

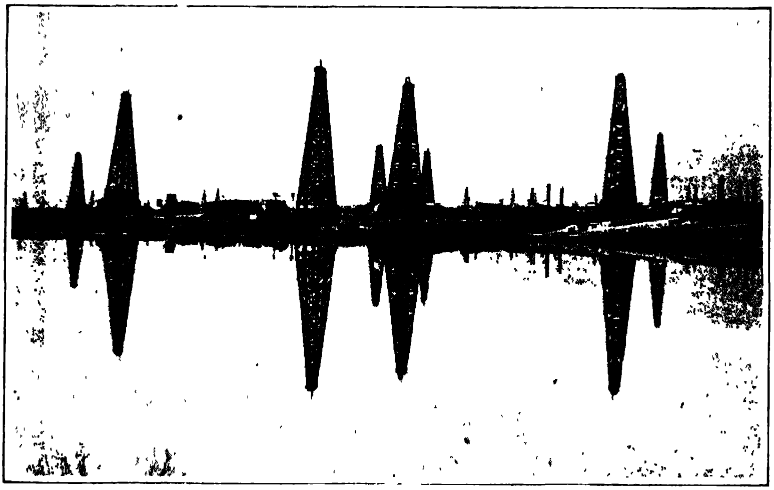


Fig. 309.—A large earthen reservoir for oil storage, Sunset Field, California.

volume of oil is flowing from the well without adequate tankage being available to care for it. In such a case, earthen reservoirs may be constructed as temporary places of storage until tankage can be provided (see Fig. 309).

The usual method of constructing such a reservoir is to excavate with plows and scrapers to a depth of a few feet over a large area, piling the earth so removed around the edge of the excavation to form an embankment which further increases its depth. If there is time, the bottom and walls of the reservoir may be lined with clay and rolled. Such a reservoir must of necessity conform more or less to the topography of the site selected, sometimes being long and narrow, or perhaps square or circular if the ground is level. Occasionally, a dam will be built across some natural watercourse, which causes the oil to accumulate over a wide area behind it.

One corner or end of such a reservoir should always be lower than the others, and the bottom should be sloped toward the low spot so that the reservoir may be completely drained when desired. In order to reduce

seepage losses, which must necessarily be serious in a reservoir of this character, care should be exercised in choosing the site to avoid sandy soils, selecting rather a compact soil with considerable clay if possible. Since such a reservoir is usually of a temporary character, it is seldom advisable to roof it over. The exposed surface being relatively large in proportion to the volume of oil stored, evaporation losses will be excessive. Ground water should be kept out of the reservoir as far as possible by digging trenches around it on the upper slopes. The accumulation of a certain amount of ground water and rain water will be unavoidable, however—particularly if the reservoir site is traversed by a natural watercourse—and the water from these sources will tend to accumulate in the lower corner or end of the reservoir from whence it must be occasionally drained by properly placed pipes.

Pump suction piping connecting with a pipe line transportation system must be eventually provided, and pipes of adequate size for this purpose, equipped with suitable valves, must be carried through the lowest corner of the embankment when the reservoir is constructed.

Fire Prevention and Control in Oil Storage Tanks and Reservoirs

In securing protection against fire, it is important not only to provide apparatus for fire control, but also to adopt such methods of construction and design and such precautionary measures as will prevent fires (see Fig. 310). The advantages of gas-tight roof construction for oil storage tanks have already been discussed. Gas explosions, or transmission of flame to the oil surface by burning gas is the immediate cause of practically all oil tank fires; hence, if the gas can be absolutely confined within the tank, without admixture with air, fires will be largely prevented. Water-top tanks and other forms of gas-tight roof construction are important developments in this direction. If the tank roof can be made moderately secure against leakage, an open 4-in. pipe penetrating the roof may carry the oil vapors to a safe distance from the tank. Circular earthen dikes and firewalls about storage tanks are customarily provided to prevent spreading of fires from one tank of a group to others (see Fig. 290). Tanks must be widely spaced (at least 600 ft. between centers) to further minimize this risk. Naked lights and electric wiring should not be permitted in the vicinity of an oil storage tank, and smoking should be prohibited.

Many tank fires are occasioned by lightning and static discharges, and to guard against this menace the tank roof and shell must be electrically grounded. The tank roof should be electrically bonded to the shell plates by two heavy wires running from the apex of the roof to the side plates below the top flange, and the shell may be effectively grounded by making electrical connections with two 1-in. pipes placed 180 deg.

apart on the tank's circumference, and embedded in moist charcoal or driven to permanently moist subsoil.

Steam, which has been so effectively used in extinguishing many oil and gas well fires, has also been widely employed in combating tank fires. If the tank roof is moderately secure against gas leakage, live steam forced into the air space above the oil will rapidly smother a fire at the oil surface. In cases where the fire is initiated by an explosion which wrecks or partially wrecks the tank roof, the steam cannot be confined, and is so rapidly vaporized by the flame that it becomes ineffective.

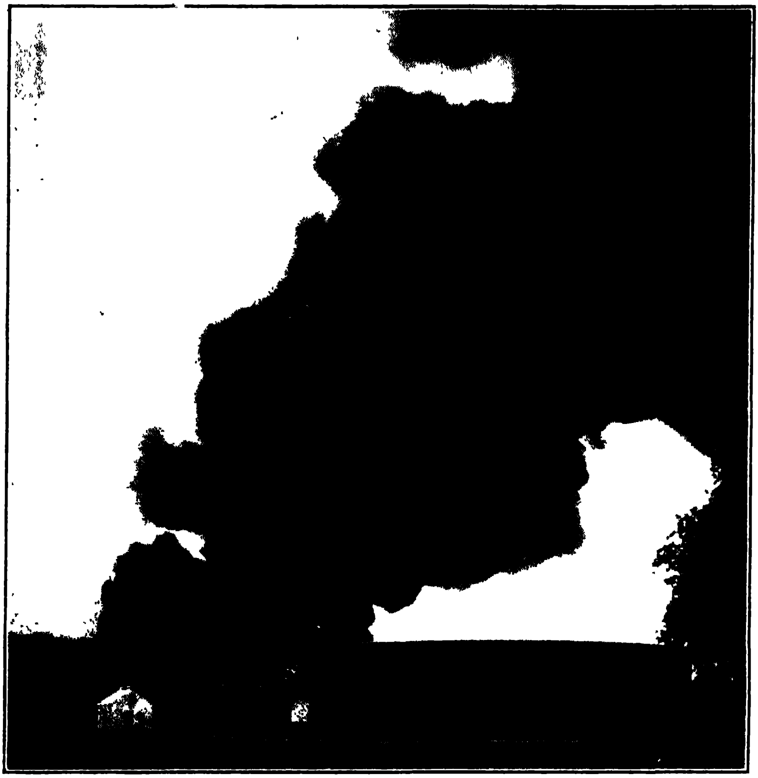


FIG. 310.—An oil tank fire.

The most reliable method yet devised for extinguishing tank fires involves rapid application of a carbonic acid froth over the oil surface, which blankets the oil, preventing contact with air and depriving the flames of oxygen to support combustion. Mixture of a solution containing any soluble acid salt with a solution of bicarbonate of soda will liberate carbonic acid gas, but to form a semi-permanent froth that will withstand the heat of the flame, glue, glucose or other viscous materials must be used in one of the two solutions. Most of these organic froth-forming

substances are subject to bacterial decomposition unless preservatives are used. One of the most successful froth-forming agents for this purpose is a concentrated licorice extract, patented and marketed under the name of "Firefoam."* This preparation is unaffected by temperature changes, and is not subject to bacterial decomposition. The following formulas involving the use of this substance are widely used:

Acid Solution	Per Cent	Carbonate Solution	Per Cent
Aluminum sulphate	13	Sodium bicarbonate	8
Water	87	Foamite or fire foam	3
		Water	89

Equal volumes of these solutions, properly mixed, will produce from six to eight times their combined volumes of foam which on being applied to a burning oil surface expands and spreads rapidly until the entire surface of the tank is covered. The froth, furthermore, is resistant to heat and will last several hours, or until the oil and tank metal has had time to cool below the danger point.

In the application of this system of fire protection, the acid and carbonate solutions are kept in tanks ready for use, and a parallel system of piping with suitable valve control conducts them separately to each oil storage tank. In time of fire, a high-pressure twin-duplex pump, steam- or motor-driven, serves to force the solutions rapidly through the piping to any tank of the group. The two lines to each tank terminate in a mixing chamber hung on the upper edge of the tank shell, discharging froth into the tank at the level of the roof flange. The piping system must be designed for prompt control, and the pump must be ready for instant service. The froth-forming solutions must be available in ample quantity, and should be tested occasionally to determine whether or not they are in condition for efficient use. For each 55,000-bbl. tank, the system should be capable of delivering 535 gal. of each of the two solutions per minute; for a 10,000-bbl. tank, 110 gal. per minute; and for a 1,600-bbl. tank, 50-gal. per minute. The quantity of chemical solution necessary to maintain in storage will depend upon the number and size of the tanks to be protected, but there should be sufficient to continue delivery at the above rate, for at least 5 min. Where a group of tanks must be protected, as in a tank farm, the froth-forming solutions should be stored in sufficient quantity to combat fires in several different tanks simultaneously. Precautions must be taken against freezing of the foam-forming solutions in cold weather; but on the other hand, if steam coils are used to prevent this, excessive heating should be avoided, since it results in the bicarbonate solution changing over, in part, to the normal carbonate, which is less active in its foam-forming properties.

* Manufactured by Foamite-Childs Corporation, Utica, N. Y.

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CHAPTER XVIII

TRANSPORTATION OF PETROLEUM

Methods of Transporting Petroleum and Their Relative Economic Importance.—The transportation of petroleum and petroleum products may be accomplished either in bulk or in special containers, such as barrels, drums or cans. The latter are never used in the handling of crude petroleum, however, so that the producer is interested primarily in bulk transportation.

While the railroad tank car, the inland river and lake barge, the ocean-going tank ship and the motor truck share to some extent in the business of transporting crude petroleum, by far the most important factor in modern petroleum transportation is the oil pipe line. About 90 per cent of America's domestic crude petroleum production is passed through pipe lines on its way from the producing fields to the refineries or the marketing centers. There is a general belief that pipe line transportation is confined to crude petroleum, but this is not necessarily the case. There is a pipe line which now transports refined oil from refineries in west Pennsylvania to the Atlantic seaboard. That its total movement is substantial is indicated by the fact that one company reports receipts through this line amounting to 40,000 tons per month. The further application of pipe line transportation to the problem of moving refined oils from interior refineries is not beyond the possibilities of the future.

Water transportation of oil in tank ships ranks second in economic importance as an element in petroleum transportation. From an international point of view, this method of transportation would rank first. In addition to a large domestic coastal movement, all of our foreign trade, aggregating in both imports and exports more than 200 million bbl. per year (1922), is conducted in "tankers." Much of our inland distribution of petroleum is facilitated by the use of small barges, operating on the larger rivers, canals and lakes.

The railroad tank car ranks third in importance as a bulk carrier. In 1920, 9.3 per cent of our domestic production of crude petroleum was moved by tank cars. The railroad ranks first in the United States as a carrier of refined petroleum products, carrying in 1920 more than 51 per cent of the refined products that went into domestic consumption.

Since the oil pipe line is by far the most important method of accomplishing bulk transportation, particularly from the point of view of the

producer with whose interests we are chiefly concerned, the greater part of the space available in this chapter will be devoted to the transportation of petroleum by this method.

Historical Development of the Oil Pipe Line.—The transportation of crude petroleum through pipes was first accomplished in the Oil Creek district of Pennsylvania in 1865. Prior to this time petroleum had been transported at great cost in barrels with the aid of wagons, carts and small boats and barges. While entirely successful, the pipe line was only used during the early years of its development in transporting oil from the wells to near-by railroads, long-distance transport being accomplished by means of the railroad tank car. Later, when the oil industry was freed to some extent from the dominating influence of the railroads, trunk pipe lines were constructed, connecting the Pennsylvania fields with the Atlantic seaboard. The success of these early lines and the marked decrease in transportation cost effected by them, in comparison with railroad transportation, brought about the universal acceptance of the pipe line as a transportation medium, in preference to all other methods. Thereafter, one of the first considerations of the interests in charge of the development of a new field has always been the provision of pipe line facilities of adequate capacity to carry the product to a refining center or other distributing point.

The discovery of new oil fields in many widely scattered regions of the United States, and the necessity for distributing petroleum among many of the more important industrial centers of the country, have brought about the gradual development of a system of main trunk pipe lines (of 6-in. diameter or larger—mostly 8-in.), which in 1921 aggregated more than 50,000 miles in length. In addition to these main arteries there are about 12,000 miles of smaller sized laterals and gathering lines, operated as an integral and essential part of the entire system.

It is estimated that the movement of petroleum through these pipe line systems aggregated 100,000,000 ton-miles daily during 1920. The railroads of the United States moved a total of approximately 1,000,000,000 ton-miles of freight daily during the same year.

Oil is transported by pipe line at the present time from the mid-continental fields of Oklahoma and Texas to the Atlantic seaboard in New Jersey, a distance of more than 1,500 miles. Chicago, New York harbor, Philadelphia, Galveston, Baton Rouge, Port Arthur and other Lake, Atlantic and Gulf ports, important refining and distributing centers for Appalachian and mid-continental petroleum, are connected by pipe lines with the producing fields. In California and the Rocky Mountain states of Wyoming and Montana there have been developed smaller isolated pipe line systems. California's oil pipe line system aggregated, in 1921, about 3,000 miles of trunk pipe of 6-in. size or larger, every field in the state being provided with pipe lines terminating at one or another

of the several Pacific ports where most of the oil is refined and distributed to the foreign and domestic trade.

While by far the greater part of the world's oil pipe line mileage is located within the United States, there are a few notable pipe lines in other parts of the world. One of these, an 8-in. line connecting the Baku oil fields of Russia with the Black Sea port of Batoum, traverses a distance of 550 miles through one of the most rugged regions of eastern Europe. Until the completion of the Panama Canal, an 8-in. line was engaged in transporting oil between Panama and Colon. Though the Mexican fields are comparatively near the coast ports, through which practically all of the Mexican product passes on its way to American and European markets, a considerable mileage of trunk pipe lines has already been constructed by the oil companies operating in that region.

Pipe line transportation of the comparatively non-viscous oils of the Appalachian region presented little or no difficulty, moderate pressures or even gravity flow methods being adequate for the purpose; but with the development of the San Joaquin Valley fields of California, producing heavy viscous oils in great abundance, a new problem was presented. The oil from these fields was found to be so viscous that it was impossible with Pennsylvania methods to operate a pipe line at any reasonable capacity. Pipe line engineers dealing with the problem early conceived the idea of heating the oil at each pumping station to reduce its viscosity, a practice which led to the development of the "hot oil" system of pumping. In 1903 the first California hot-oil line was completed, a line about 300 miles long, with pumping stations spaced about 24 miles apart. The line was not an operating success, however, until the number of pumping stations had been doubled and their distance apart reduced to 12 miles. So successful has this method since proved that it is now used exclusively wherever heavy viscous oils are to be moved.

Typical practice in hot-oil pumping involves the use of 4, 6, 8, 10 or 12-in. pipe, with pumping stations spaced apart at distances ranging from 11 to 30 miles, depending upon the viscosity of the oil and its tendency to cool. Powerful pumps develop oil pressures ranging as high as 800 lb. per square inch. Initial temperatures at each pumping station range from 120 to 180° F., and receiving temperatures from 60 to 120° F. The capacity of an 8-in. line, the size most commonly used, operating under normal conditions, ranges from 15,000 to 25,000 bbl. per 24 hr.

In the search for a method of pumping that would avoid the expensive process of heating the California oil, and that would make possible the operation of a pipe line with a smaller number of pumping stations, a plan was developed which led, in 1907, to the building of the "rifled" pipe line.[5] This line is 282 miles in length, constructed of 8-in. pipe, in the periphery of which a long spiral groove was indented prior to coupling, with the aid of a specially developed machine. Pumping stations were

placed 23 miles apart. Oil with 10 per cent of water, injected into this pipe under high pressure, assumes under the influence of the spiral grooving of the pipe, a rapid rotation. This rotation, through the action of centrifugal force, results in most of the water following the perimeter of the pipe, while the oil flows through this cylinder of water, scarcely making contact with the metallic walls of the pipe. The friction of oil on water, thus substituted for the viscous drag of oil on metal, resulted in an increase in capacity of an 8-in. line carrying 14° California crude, from 2,000 bbl. per day to 24,000 bbl. The oil was not heated. While the rifled pipe line was regarded in its day as a success from every point of view, the transportation of 1 bbl. of worthless water with each 9 bbl. of oil, with the necessary provision of special tanks and pumps to handle the water at each pumping station, proved expensive. Furthermore, the water had a tendency to form emulsions with the oil during transmission, necessitating dehydration of large volumes of oil at the terminal of the line. The rifled pipe line of California, the only one of its kind ever built, is now operated as a hot-oil line.

Flow of Oil through Pipes, Theoretical Considerations

Early attempts at pipe line design, while based on generally accepted hydraulic theory, were found to be in error because the formulas in use contained no variable to express the influence of viscosity. Indeed, it is only within comparatively recent years that the laws of viscous and turbulent flow have been properly understood and evaluated, and mathematical expressions for them developed. Having nothing more than empirical formulas of doubtful value, and data from preëxisting lines on which to base new designs, engineers have naturally been reluctant to diverge to any great extent from established practice. In most of the pipe lines and pumping stations now in use, there is a remarkable uniformity in design that is undoubtedly an expression of the uncertainty and unreliability of the empirical formulas which for many years the engineer was compelled to use.

When oil is pumped through a pipe, its transmission is opposed by frictional resistance to flow which is a product of two factors. The first of these is the frictional resistance developed between the inner wall of the pipe and the outer cylinder of oil making contact therewith. The second is due to the internal resistance to movement of the oil itself, the fluid friction resulting from many oil surfaces sliding over each other throughout the entire cross-section of the pipe. Viscosity is a measure of this internal resistance of a fluid, by which it opposes movement of its parts with respect to each other. The magnitude of the resistance offered by these frictional forces will depend upon the length of the pipe

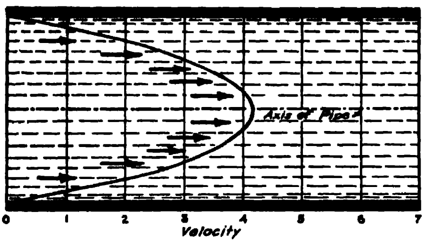
through which the oil is pumped, the velocity of flow, the condition of the pipe's inner surface and the viscosity of the oil. The latter property will vary within wide limits with changes in temperature of the oil. In addition to frictional resistance, if the oil must be pumped to a higher elevation than its source, energy must be expended in lifting the oil. The elements of this latter phase of the problem include the height of lift, the density of the oil and the rate of flow.

The motivating agent enabling the oil to overcome these several resistances to flow is the pump, which imparts a certain initial pressure to the oil, by virtue of which it moves through the pipe, overcoming the resistance interposed, until the pump pressure is entirely consumed. If flow is to continue, the oil must then be given new impetus by passing it through a second pump. The pressure loss per unit length of pipe is seen to be a quantity of prime importance in all pipe line calculations. Knowing this for a given set of conditions, it will be possible to calculate the distance through which oil may be transmitted with a given initial pressure; or the necessary initial pressure to accomplish transmission over a given distance may be determined.

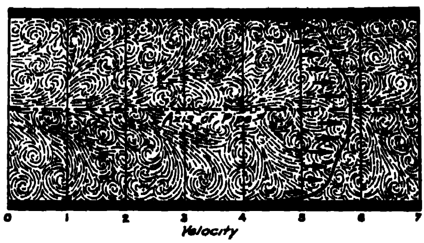
Viscous Flow.—Oil tends to adhere to any metal surface with which it may come in contact. Because of this tendency, when oil flows through a pipe, a cylindrical oil film forms on the inner surface of the pipe. At low speeds of oil flow within the pipe, this outer film is supposed to be almost stationary because of the adhesive force exerted between the metal and oil surfaces. Within this stationary or slow-moving cylindrical film of liquid, slides another liquid cylinder, also at a relatively slow speed because of its contact with the outer stationary film. Within this second cylinder slides a third at somewhat higher velocity; within that, another moving still faster, and so on, until at the center of the pipe, the maximum velocity is reached. If we represent these cylindrical films by lines drawn in the axial cross-section of the pipe, and indicate their respective velocities by arrows drawn to scale, we obtain the result indicated in Fig. 311. The line connecting the points of these arrows is seen to develop a curve of sharp hyperbolic form.[7] The general form of this curve for any given pipe depends chiefly upon the quantity of oil flowing. It will have practically the same shape regardless of the condition of the inside surface of the pipe or the viscosity of the oil. The average velocity throughout the cross-section of the pipe will be about half that of an oil particle at the center.

As long as this simple orderly condition of affairs exists within a pipe, the computation of pressure loss is a comparatively easy matter. It varies directly with the speed. In other words, with "viscous flow," as this orderly type of flow is called, if we double the pressure which we apply at one end of a level pipe line, the oil will flow through the line twice as fast and we can get twice as much through in a given time.

Critical Velocity and Turbulent Flow.—As the flow velocity increases, however, it is found that the orderly system of flow just described is no longer followed. Eventually a speed known as the "critical velocity" is reached, where "turbulent flow" supercedes viscous flow—the cylindrical oil films, unable to slide rapidly enough upon each other, are turned inside out upon themselves, and a confused, eddying, swirling movement of liquid particles results[7] (see Fig. 312). Probably the rough interior surface of the pipe is largely instrumental in inducing turbulence. The net result is a tendency to equalize the velocity throughout the pipe so that an axial cross-section shows a curve of rather blunted appearance.



(*After Standard Oil (California) "Bulletin"*).
FIG. 311.—Illustrating viscous flow.



(*After Standard Oil (California) "Bulletin"*).
FIG. 312.—Illustrating turbulent flow.

When the critical velocity is reached, certain very definite indications are in evidence. The most noticeable indication is that a considerable increase in pipe line pressure does not result in a corresponding increase in the rate of flow. In other words, this eddying or swirling motion, which we have called turbulence, results in serious loss of energy; that is, the internal resistance of the liquid to movement is increased. Much of the initial pressure imparted to the oil by the pump is used up in restoring energy to particles that have been stopped by collision, and as a result a given initial pressure can force much less oil through the line than it could if the flow were non-turbulent. The energy of motion possessed by any flowing particle of oil varies with the square of its velocity. Hence the energy consumed in restoring velocity to particles which have been stopped during turbulent flow, depends on the square of their velocity. In other words, if resistance due to turbulence were the only resistance to overcome in forcing liquids through pipes, doubling any given rate of flow would require four times the pressure.

Flow Calculations.—It is well established as the result of a number of independent investigations, that Poiseuille's formula holds for viscous flow conditions. Expressed in convenient engineering units, this formula is as follows:[12]

$$P = \frac{.000668\,ZLV}{D^2\,S} \tag{1}$$

in which P is the pressure drop in pounds per square inch; Z is the absolute viscosity of the oil in centipoises (relative to water at 68°F.); L is the length of the pipe in feet;

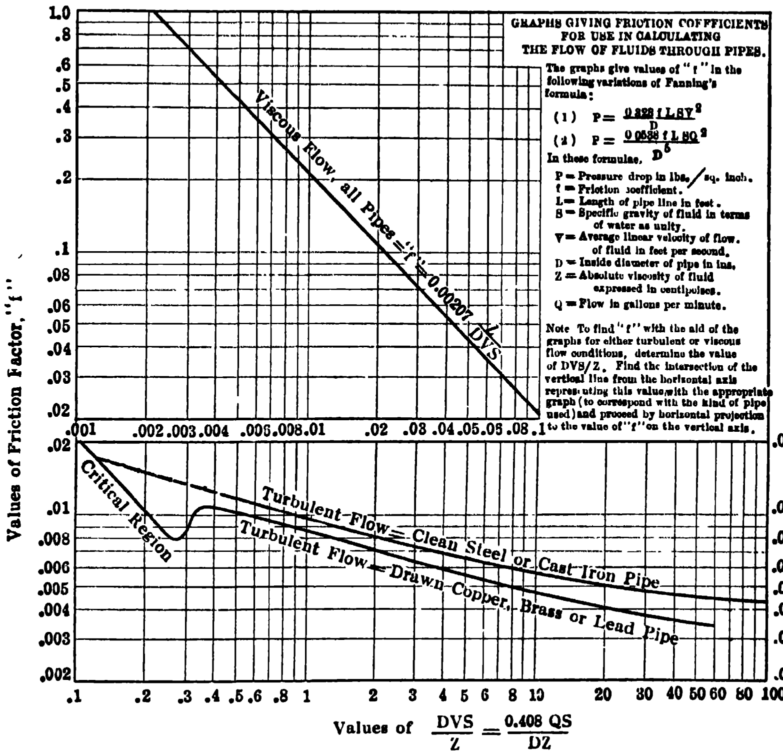
V is the average linear velocity of flow through the pipe in feet per second; S is the specific gravity of the oil; and D is the inside diameter of the pipe in inches.

A formula commonly used for turbulent flow computations is that of Fanning,[13] which may be expressed in either of the following two forms:

$$P = \frac{.323\, f\, LSV^2}{D} \tag{2}$$

$$P = \frac{.0538\, f\, LSQ^2}{D^5}. \tag{3}$$

In these formulas, P, S, L, V and D have the same significance as in Poiseuille's formula given above. Q is the flow in U. S. gallons per minute; and f is a friction factor which is a function of the ratio of $\frac{DVS}{Z}$. It appears that if $f = .00207\,\frac{Z}{DVS}$,



(*After Wilson, McAdams and Seltzer in Jour. Ind. & Eng. Chemistry*).

FIG. 313.—Graphs giving friction coefficients for use in calculating flow of fluids through pipes.

Fanning's equation becomes identical with that of Poiseuille. It is therefore possible, by selecting proper values for f, to use Fanning's equation for calculations in both viscous and turbulent flow. Furthermore, since all fluids obey the same laws, these equations are applicable to computations of flow of other liquids than oil, as well as to gas flow.

As a result of a series of experiments conducted by the National Physical Laboratory of London,[4] the Research Laboratory of Applied Chemistry of the Massachu-

setts Institute of Technology[12] and several individual investigators, values for f have been determined for oil flow through commercial pipes over a wide range of values of D, V, S and Z. These are reproduced in the graph given in Fig. 313.

Varying results are obtained in tests made within the region of critical velocity, the change from viscous flow to turbulent flow, or vice versa, coming at different velocities with slight variation in surrounding physical conditions. Laboratory investigation within the critical flow region has shown that viscous flow has a marked tendency to perpetuate itself under conditions where turbulent flow would normally be expected. Hence the dip in the curve (Fig. 313) connecting the viscous flow curve with the turbulent flow curves. Most authorities agree that if the critical region be approached by gradually lowering the velocity from the turbulent flow side, the tendency is to follow the turbulent flow line without deflection to a direct intersection with the straight viscous flow line. Increasing the velocity from viscous flow conditions, however, may result in the viscous flow curve perpetuating itself beyond the normal intersection into the relatively unstable critical region. Here any slight disturbance in the pressure equilibrium will result in the curve bending sharply upward to meet the normal turbulent flow line. It would appear preferable in the practical solution of flow problems, to assume that the turbulent flow curve extends directly (as shown by the dotted line in Fig. 313) to its intersection with the viscous flow line. This simplifies the calculations, and if the resulting calculation is slightly in error, it will be on the "safe" side.

Flow computations with the aid of formulas 1, 2 or 3, and the graphs in Fig. 313 giving values of f, are conducted as follows:[12]

1. Calculate the value of $\frac{DVS}{Z}$ (or its equivalent $\frac{.408\,QS}{DZ}$, if Q is known rather than V).

2. By referring to the graph, Fig. 313, find the value of f which corresponds to this value of $\frac{DVS}{Z}$; if Q is known rather than V we may substitute for V its equivalent, $\frac{.408\,Q}{D^2}$, in which case the expression $\frac{DVS}{Z}$ becomes $\frac{.408\,QS}{DZ}$.

3. Insert this value of f in either equation (2) or equation (3), above, and solve for whatever variable may be unknown.

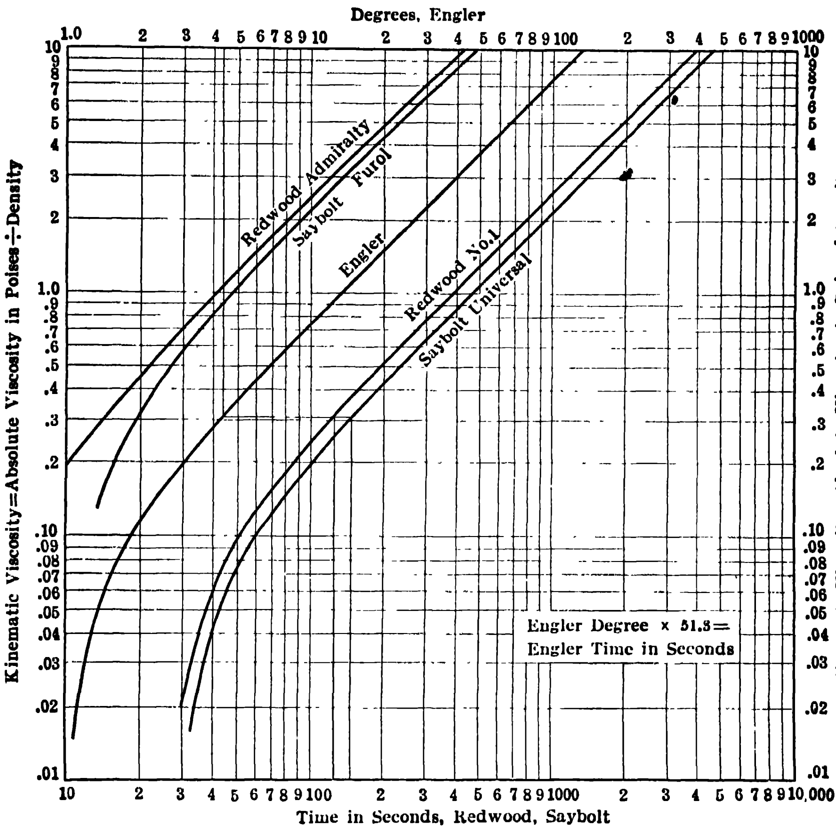
Accurate results should not be expected from these formulas when the pipe line is less than 500 diameters in length, or when the pipe is badly corroded or tuberculated on its inner surface; or when there is any tendency to separate out solids (such as paraffin wax) on the walls of the pipe.

If the pipe line contains elbows, these will be equivalent in resistance offered to flow, to about 30 diameters of the pipe for each elbow.

Determination of Absolute Viscosity.—Determination of the value of Z will ordinarily require a viscosity test with one or another of the several types of commercial viscosimeters. This test must be conducted at the average temperature assumed to prevail within the pipe line during the period of flow. The instruments commonly available for this purpose do not determine the true absolute viscosity of the oil, but give values measured in seconds of time which can be converted to equivalent absolute viscosity* with the aid of

* In physical terms, the absolute viscosity of a fluid is that tangential force, expressed in dynes, necessary to move a unit area of plane surface, with unit speed, relative to another fixed plane surface at unit distance from it, the oil in question being in contact with and between the two surfaces. In the c.g.s. system, absolute viscosity is expressed by a unit called a "poise," which is one dyne-second per square centimeter. A "centipoise" is one one-hundredth part of a poise. The viscosity of water at 68°F. is 1 centipoise; hence, if the viscosity of an oil is expressed in centipoises, it may be visualized as a multiple of the viscosity of water at this temperature.

mathematical formulas* or by means of graphs such as those reproduced in Fig. 314. Absolute viscosity divided by density $\frac{Z}{S}$ is the so-called kinematic viscosity. The reciprocals of values of $\frac{Z}{S}$, indicated along the vertical axis of Fig. 314, are used



(*From graphs published by Power Specialty Co., New York, with additions*).

FIG. 314.—Chart for converting viscosimeter readings to equivalent kinematic viscosity.

* Absolute viscosity may be calculated from measurements made with either the Saybolt Universal, Engler or Redwood viscosimeters, by means of the following approximate formulas established by the U. S. Bureau of Standards:

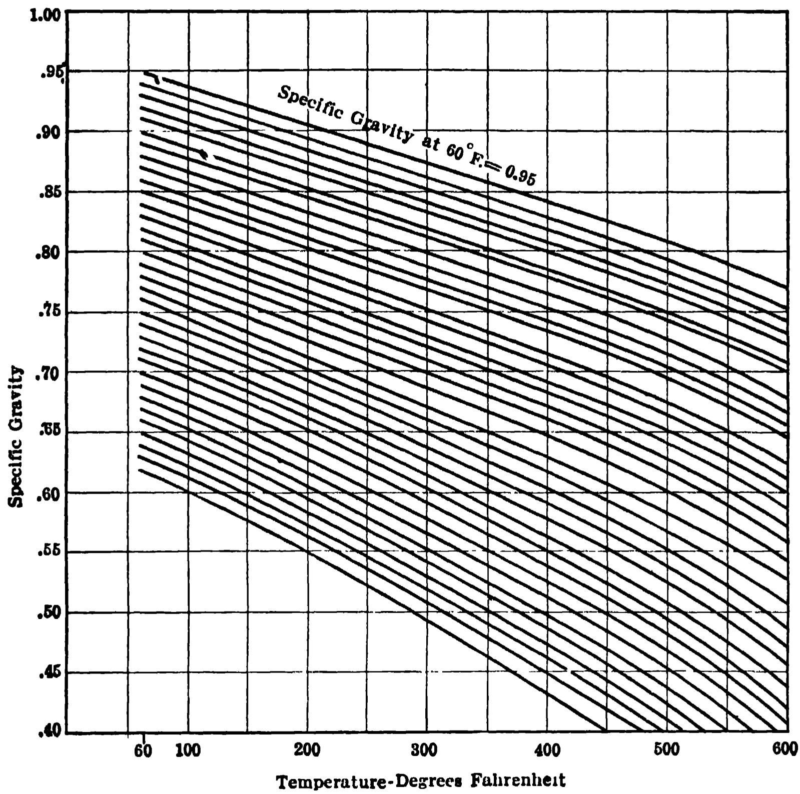
For the Saybolt Universal instrument $\frac{Z}{S} = .00219\,t - \frac{1.497}{t}$

For the Engler instrument. . . . . $\frac{Z}{S} = .00144\,t - \frac{3.22}{t}$

For the Redwood (No. 1) instrument . . $\frac{Z}{S} = .00260\,t - \frac{1.561}{t}$

In these formulas, t is the time of outflow in seconds, of the standard volume of the oil from the instrument; Z is the absolute viscosity expressed in poises; and S is the density (equivalent of specific gravity) at the temperature of the test.

directly in the expression $\frac{DVS}{Z}$ or $\frac{.408\,QS}{DZ}$ in determining the Fanning formula coefficient. If, for any purpose, the absolute viscosity, Z, is required, instead of the kinematic viscosity, $\frac{Z}{S}$, it may be readily obtained by multiplying the kinematic viscosity by the density, S. With the aid of the graphs reproduced in Fig. 315,



(From graphs published by Power Specialty Co., New York, with additions).

FIG. 315.—Chart showing variation in specific gravity of petroleum at different temperatures.

densities at high temperatures may be determined from those corresponding to lower, temperatures at which gravity measurements are ordinarily conducted.*

* If the gravity of the oil is measured in Baumé degrees at 60°F., as is customary conversion to equivalent specific gravity may be accomplished with the aid of the following formula:

$$\text{Specific gravity at } 60°\text{F.} = \frac{140}{\text{Degrees Baumé at } 60°\text{F.} + 130}$$

This formula is recommended by the U. S. Bureau of Standards, but a Baumé scale adopted by the American Petroleum Institute and known as the *A.P.I.* scale is based on the modulus 141.5 instead of 140, thus:

$$\text{Specific gravity at } 60°\text{F.} = \frac{141.5}{\text{Degrees Baumé at } 60°\text{F.} + 131.5}$$

For use in the flow formulas, the value of Z, representing the absolute viscosity, must be that corresponding to the average temperature of the oil in the line during transit. Inasmuch as this temperature is not generally known at the time the viscosity determinations are made, it is customary to develop a viscosity temperature curve for the oil to be pumped, showing its viscosity at all temperatures up to the maximum to which it is to be subjected. The construction of such a graph would require determinations of viscosity at several different temperatures, from which values, when plotted on coordinate paper, a smooth curve may be developed. The curves repro-

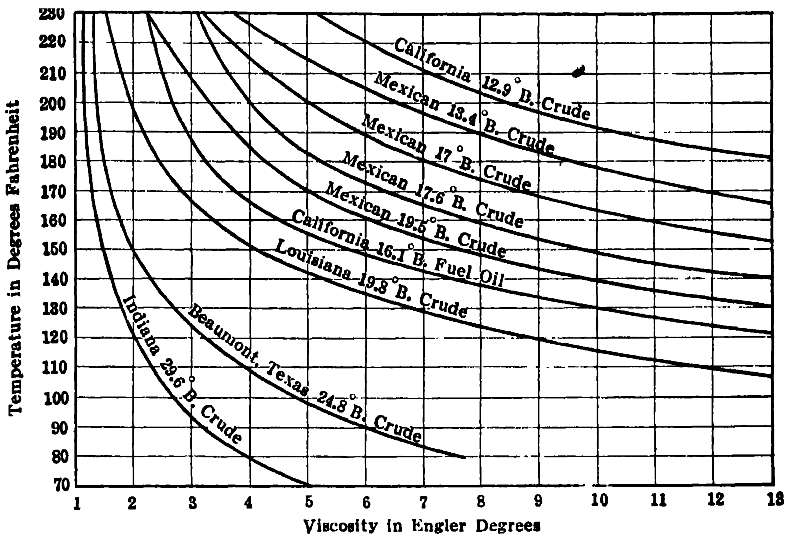


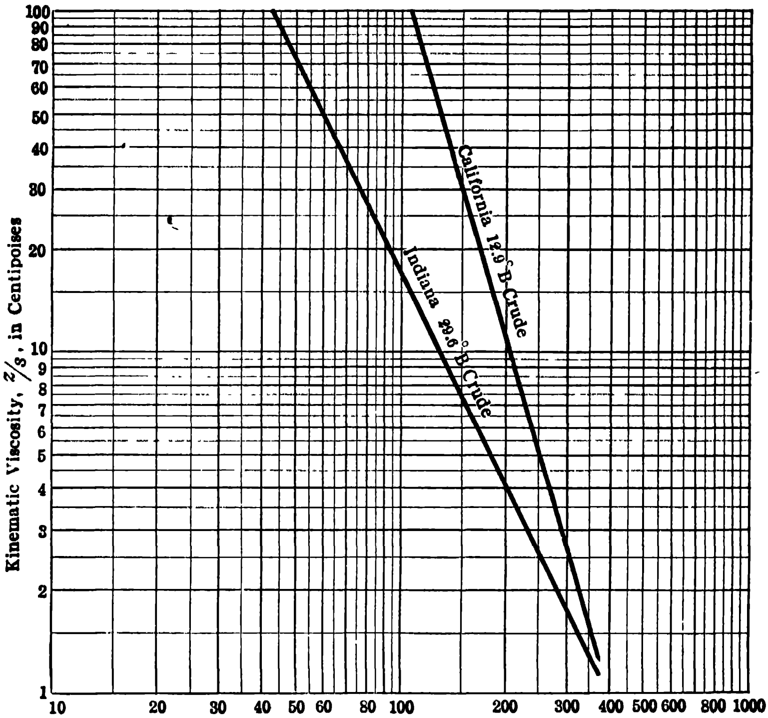
FIG. 316.—Viscosity-temperature graphs plotted with respect to normal coördinates.

duced in Fig. 316 are typical. Since viscosity measurements, if accurately made, consume considerable time, it is preferable to plot the absolute values on logarithmic coordinate paper, in which case the graph becomes practically a straight line over the greater part of its course. Two viscosity tests at different temperatures will suffice to determine the course of this line, from which absolute viscosities at any other temperature may be determined. Fig. 317 illustrates the construction of graphs of this type.

Determination of Average Temperature.—Determination of the average temperature of the oil during the period of flow, on which the viscosity variable, Z, depends, is admittedly one of the most difficult and uncertain elements involved in pipe line design. The temperature will drop rapidly at first, near the pumping station, and less rapidly as the difference between the oil and the earth decreases. The heat lost varies with the velocity of flow (time), the area of contact surface between the heated pipe line and the surrounding earth, the specific heat of the oil and the difference between the temperature of the earth and that of the heated oil.

Heat radiation will also depend somewhat on the character of flow, the outer layers of oil, nearest the walls of the pipe, will suffer the greatest heat loss, leaving the oil toward the center relatively warmer. In turbulent flow, due to more thorough mixing of the oil, a fairly constant temperature prevails throughout the cross-section of the pipe.

In estimating the average temperature, some engineers use the following approximate formula, which is said to agree very closely with actual temperature conditions in existing lines:[7]



(*The graphs shown are the equivalent of two of those given in Fig. 316*).

Fig. 317.—Logarithmic viscosity curves illustrating straight line characteristics.

$$\text{Average temperature} = (\tfrac{1}{3}\ \text{Initial temperature}) + (\tfrac{2}{3}\ \text{Final temperature}) \tag{4}$$

Thus, if the maximum initial temperature to which it is considered advisable to heat the oil is 160°F., and the lowest temperature permissible for efficient pumping is fixed at 120°F., the average temperature in the line during transit is $160/3 + 2 \times 120/3 = 133.3$°F.

A more precise formula, recommended by H. W. Crozier,[1] is the following:

$$L = 8.8 \frac{aQWS}{D} \text{Log}_e\, t \tag{5}$$

in which

L = The length of the pipe in feet.
a = A radiation constant.
Q = Flow in barrels per hour.
W = Weight of 1 bbl. of oil in pounds.
S = Specific heat of the oil.
D = External diameter of the pipe in inches.
t = Difference in temperature between the earth and the pipe.

The following values for the radiation constant, a, were calculated from tests made on two California pipe lines:

8-in. line, pumping 26,128 bbl. of 20°Bé. oil daily.......... $a = 1.67$
8-in. line, pumping 24,494 bbl. of 17.7°Bé. oil daily........ $a = 1.75$

Influence of Gravity on Pipe Line Flow.—The foregoing discussion has taken no account of differences in elevation which may exist at different points along the pipe line. If the line carries oil over some point at a higher elevation than the initial point, obviously, more pressure will be necessary than that which is barely enough to overcome pipe resistance; and on the other hand, if all points along the line are below the initial point, gravity will aid flow, and the necessary pressure will be lower.

In order to measure the effect of gravity on flow, it is customary to prepare a profile of the ground over which the pipe passes, and superimpose upon it a pressure diagram, showing by means of a "grade line," the "head" in feet at any point. Head in feet may then be converted to equivalent pressure in pounds per square inch, and either added to or subtracted from the value of P (the initial pressure) in the formula used for computing flow, depending upon whether the net effect of gravity assists flow, or opposes flow.

Equivalent Length of Pipes of Different Sizes.—Often intercommunicating pipe lines are operated in parallel, a device for increasing capacity known as "looping"; and in other cases, different sizes of pipe, connected end to end, will be used in different portions of the same operating division. In making flow computations in such cases, it is convenient to reduce all sizes to a common basis by making use of factors giving the equivalent length of various pipe sizes in terms of the one adopted as standard for the computations.[10] Thus, Table XLIII shows that 1 ft. of 4-in. pipe introduces as

TABLE XLIII.—EQUIVALENT LENGTHS OF VARIOUS SIZES OF PIPE LINES

Size of pipe, in.								Arrangement of lines		
2	3	4	5	6	8	10	12	Single	Double	Triple
1	7.6	32.0	97.5							
	1.0	4.2	12.8	32.0	134.9	. . .	. . . .	1	4	9
		1.0	3.0	7.6	32.0	97.5	.		1	2¼
			1.0	2.5	10.9	32.0				
				1.0	4.2	12.8	32.0			
					1.0	3.0	7.6			
						1.0	2.5			

much resistance to flow as 7.76 ft. of 6-in. pipe, and is also equivalent to 30.61 ft. of 8-in. pipe in the resistance offered. Again, 1 ft. of a single pipe of any size offers four times as much resistance as the same length of two lines of the same size connected in parallel, and nine times as much as three parallel, intercommunicating lines. These factors may be calculated from the known relationship between the carrying capacity of a pipe and the $\frac{5}{2}$ power of its diameter.

Problems Illustrating Use of Pipe Line Formulas.—The following applications will illustrate the use of the foregoing formulas in typical pipe line problems:

1. It is desired to transmit crude petroleum of 28°Bé. gravity through an 8-in. pipe line at the rate of 20,000 bbl. per 24-hr. day. The initial temperature of the oil is to be 160°F., and the final or delivery temperature, 120°F. The initial pressure is to be 750 lb. per square inch. What is the maximum distance at which the pumping stations on this line may be spaced?

Solution:

Viscosity tests with a Saybolt Universal viscosimeter, on the oil to be pumped, show the following time of efflux: (*a*) At 100°F., 143 sec., and (*b*) At 150°F., 60 sec.

With the aid of formula (4), we calculate the average temperature of the oil during transmission:

$$\text{Average temperature} = \frac{160}{3} + \frac{(2 \times 120)}{3} = 133°\text{F.}$$

With the aid of the viscosity conversion chart (Fig. 314), we find the equivalent kinematic viscosities to be:

(*a*) At 100°F., kinematic viscosity = 0.30 poises = 30 centipoises.
(*b*) At 150°F., kinematic viscosity = 0.10 poises = 10 centipoises.

Constructing a logarithmic temperature-viscosity curve from these values for the kinematic viscosity (as illustrated in Fig. 317), we are able to determine that at 133°F., the average temperature, the oil will have a kinematic viscosity of 13.5 centipoises. This is the value of $\frac{Z}{S}$ to be used in determining the friction coefficient, f.

The gravity of the oil at 60°F. is given as 28°Bé. The equivalent specific gravity is 0.89 (this may be calculated with the aid of the formula given in the footnote on page 554, or, it may be obtained from printed tables or charts). With the aid of the curves given in Fig. 315, we are able to determine the specific gravity of this same oil at 133°F., the average temperature of the oil during transmission. The specific gravity at the higher temperature is 0.87.

In order to determine f, the friction coefficient, we must first calculate the value $\frac{DVS}{Z}$, or its equivalent, $\frac{0.408QS}{DZ}$. Not having at hand the velocity of flow, V, we calculate the latter quantity:

$$\frac{.408QS}{DZ} = \frac{0.408 \times \frac{(20{,}000 \times 42)}{24 \times 60}}{8.071 \times 13.5} = 2.2.$$

The actual inside diameter of 8-in. pipe is obtained from Table XLIV, as 8.071 in. Twenty thousand barrels per 24-hr. day $= \frac{(20{,}000 \times 42)}{(24 \times 60)} = 583.8$ gal. per minute. By reference to the graph given in Fig. 313, the value of f corresponding to this value of $.408\frac{QS}{DZ}$, is found to be .008.

The maximum spacing of pumping stations implies a reduction of the final or delivery pressure in the line to zero pounds per square inch. The maximum or initial pressure is given as 750 lb. per square inch. We therefore will have for the maximum spacing of pumping stations, a total pressure loss, P, of 750 lb. per square inch.

We may now calculate the value of L, the unknown distance between stations, with the aid of formula (3). Thus:

$$P = \frac{.0538 f L S Q^2}{D^5}$$

We may get the value of D^5 from Table XLVI. By substitution,

$$750 = \frac{.0538 \times .008 \times L \times .87 \times (583.8)^2}{34{,}250}.$$

$$L = 201{,}519 \text{ ft.} = 38.17 \text{ miles.}$$

TABLE XLIV.—DIMENSIONS, WEIGHTS AND DIAMETER FUNCTIONS OF IRON AND STEEL "STANDARD" AND "LINE" PIPE

Nominal diameter, in.	Actual inside diameter, D, in.	Thickness of walls, in.	Weight per foot, threads and couplings, lb.		Actual internal cross-sectional area, sq. in.	Volumetric capacity per 100 ft., bbl.	Test pressure lap-welded pipe, lb. per sq. in.		D^2	D^5
			Standard	Line			Standard	Line		
.50	.622	.109	.852	.856	3039	.038	*700	.700	.3869	.09310
75	.824	.113	1.134	1 138	5333	.066	*700	*700	.6790	.37990
1 00	1 049	.133	1.684	1.688	8639	107	*700	*700	1.1000	1.27000
1.50	1.610	.145	2 731	2.748	2 036	.252	*700	*1.200	2 5920	10.82000
							1,000	1,700		
2 00	2 067	.154	3 678	3.716	3 356	415	*700	*1,200	4 2720	37.73000
							1,000	1,800		
2.50	2 469	203	5 819	5 881	4.786	.592	*800	*1,200	6 0960	91.75000
							1,000	1,800		
3 00	3 068	.216	7.616	7.675	7.392	.914	*800	*1,200	9.4130	271.80000
							1,000	1,800		
4 00	4 026	.237	10 889	10 980	12.730	1.575	1,000	1,600	16 2100	1,058.00000
6 00	6 065	.280	19.185	19 367	28.891	3 574	1,000	1,500	36.7800	8,206.00000
8.00	8 071	.277	25.000	25.414	51.161	6.326	800	1,000	65.1400	34,250.00000
8 00	7.981	.322	28.809	29.213	50 027	6.189	1,000	1,200	63.7000	32,380.00000
10.00	10.192	.279	32.000	32.515	81.585	10 091	600	800	103.8000	109,980.00000
10.00	10 136	.307	35.000	35.504	80.691	9 978	800	900	102.7000	106,990.00000
10 00	10 020	.365	41.132	41.644	78 855	9 756	900	1,000	100 4000	101,000.00000
12 00	12.090	.330	45.000	45 217	114.800	14.203	600	800	145.9000	258,300.00000
12.00	12.000	.375	50.706	50.916	113 097	14 005	800	900	144.0000	248,800.00000
14.00	13 250	.375	55.824	56.649	137.886	17 078	700	750	175.6000	408,400.00000
16 00	15 250	.375	64.500	64.955	182.654	22.603	600	750	232.5000	824,800.00000
18.00	17.182	.409	80.482	80 659	231 866	28.681	600	700	295.2000	1,497,000.00000
20.00	19.182	.409	89 617	89.794	288.986	35 765	500	650	367.9000	2,597,000.00000

* Butt-welded pipe. Sizes from 1.5 to 3 in. may be had in either lap- or butt-weld.

Note: All sizes above 12 in. are "outside diameter" (O. D.) pipe.

2. What diameter of pipe line will be necessary to transmit 10,000 bbl. per day of crude petroleum of 15.2°Bé. gravity over a distance of 10 miles, if an initial pump pressure of 800 lb. per square inch and an average temperature of 120°F. is considered possible with the pumping and heating equipment available? The Saybolt (Furol) viscosity of the oil is 340 sec. at 90°F., and 35 sec. at 150°F.

In a problem of this type, where a variable necessary in the calculation of both the friction factor (D in this case) and the Fanning equation, is the unknown, we must adopt the method of "trial and error." That is, we must assume different values of D and select the one which brings the resultant pressure at the delivery point as nearly zero as possible. If the first approximation indicates that the proper value of f lies in the viscous flow region, Poiseuille's formula (1) will be found simpler than the modified Fanning formula.

For the given problem,

10,000 bbl. per day = 291.6 gal. per minute.

15.2°Bé = Specific gravity .96 (at 60°F.). Corresponding specific gravity at 120°F. = .942 ($=S$) (from curves given in Fig. 315).

340 sec. Saybolt Furol = Kinematic viscosity of 700 centipoises (at 90°F.)

35 sec. Saybolt Furol = Kinematic viscosity of 70 centipoises (at 150°F.)

Plotting these kinematic viscosities on a logarithmic temperature viscosity chart, we find that at 120°F. the oil has a kinematic viscosity of 190 centipoises ($=\frac{Z}{S}$).

For a trial, assume that 6-in. line pipe is used. Reference to Table XLVI shows that this pipe has an actual inside diameter of 6.065 in. ($=D$). Calculating the value of $\frac{.408QS}{DZ}$ in order to determine f, we have:

$$\frac{.408QS}{DZ} = \frac{.408 \times 291.6}{6.065 \times 190} = .103$$

From Fig. 313, f for this value of $\frac{.408QS}{DZ} = .02$.

Substituting these values of f, L, S, Q and D in formula (3),

$$P = \frac{.0538fLSQ^2}{D^5} = \frac{.0538 \times .02 \times 52,800 \times .942 \times 85,030}{8,206} = \frac{4,550,367}{8,206} = 555 \text{ lb.}$$

From this it is apparent that 6-in. pipe, under the conditions assumed, would give a delivery pressure of $(800 - 555) = 245$ lb. Hence we may use a smaller pipe.

Try 4-in. pipe. Table XLVI shows the actual internal diameter of 4-in. pipe to be 4.026 in. ($=D$). The table also gives $D^5 = 1,058$.

Calculating the value of $\frac{.408QS}{DZ}$ again, and determining the value of f in Fig. 313, we find a value of $f = .013$.

Solving again for P, we have:

$$P = \frac{9.0538 \times .013 \times 52,800 \times .942 \times 85,030}{1,058} = 2,800 \text{ lb. per square inch.}$$

Since 2,800 is greater than 800 (the initial pressure), a 4-in. line will be too small.

A similar calculation made for 5-in. pipe gives a value for P of 1,230 lb. per square inch, indicating that this size also is too small.

For 5½-in. pipe, the value of P becomes approximately 800 lb. per square inch, but since standard commercial line pipe is not made in this size, we must adopt the next largest standard size, which is 6 in.

Use of Empirical Exponential Formulas in Calculating Pressure Loss in Oil Pipe Lines.—Modifications of the well-known Hazen and Williams formula have been

widely used among engineers engaged in oil pipe line design. The following formula, recommended by H. W. Crozier,[1] is of this type:

$$V = \frac{c}{m} \times r^{0.63} \times S^{0.54} \times .001^{-0.04}. \tag{7}$$

In this formula,

V = The average rate of flow in feet per second.

r = The hydraulic radius $= \dfrac{\text{Area of cross-section of pipe}}{\text{Wetted perimeter}}$

S = The slope $= \dfrac{\text{Loss of head in feet}}{\text{Length}}$

c = A constant.

m = The average viscosity of the oil, measured in multiples of that of water at 4°C.

The relative viscosity of the oil, m, must be determined with the aid of a viscosimeter; values for the constant, c, must be determined from results obtained with existing lines. Table XLV gives values of m and c for a number of operating lines. An average value for the constant, c, is 138.

TABLE XLV.—VALUES OF c AND m IN CROZIER'S FORMULA

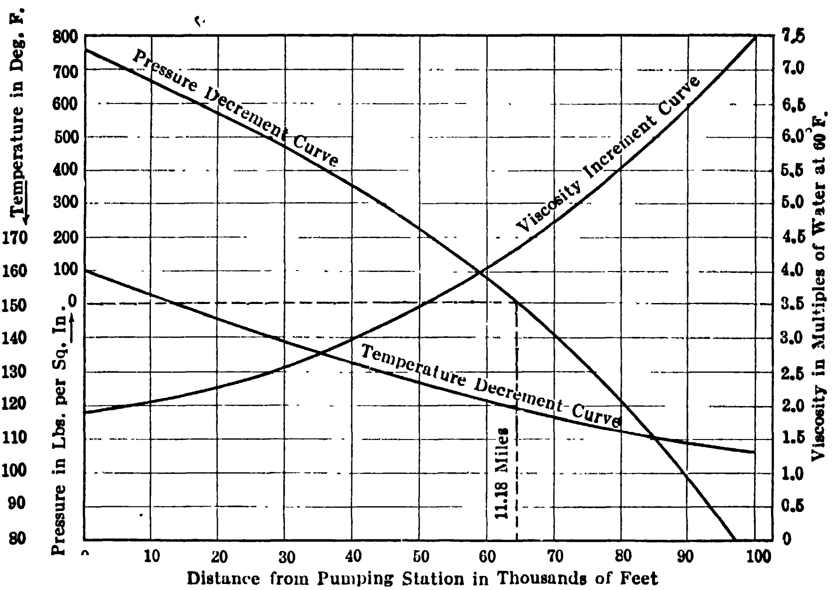
Pipe line	m	c
Monterey, 6-in. line	1.11	143
Producers', 8-in. line..	1.61	153
Ora,* 4-in. line......	1.26	124
General Petroleum Corporation, 8-in. line	1.36	136
Valley pipe line, 8- and 10-in.	1.37	138
Yarhola,* 6-in. line. . .	1.16	136
Yarhola,* 10-in. line	1.12	140

* Lines marked with asterisk are mid-continental pipe lines; all others are California lines.

In applying this formula to determine pressure loss, the unknown quantity is, of course, S, the slope. Solving for S and assuming a definite value for the length or distance from the pumping station, we can determine directly the loss of head in feet, which may then be expressed in equivalent pounds per square inch.

Pipe Line Design.—In the design of an oil pipe line, the problem as ordinarily presented specifies only a given length of line and a given daily capacity. The engineer must then select the size of pipe, the distance between pumping stations, the necessary initial pressure and the initial temperature to which the oil must be heated at each station that will enable the line to operate at the desired capacity. As a rule, the initial temperature is assumed as the highest that can be practically attained with exhaust steam in the usual type of tubular heater. In some cases, the maximum temperature to employ may be the maximum safe temperature, bearing in mind the flashpoint of the oil and the tendency of the lighter constituents of the oil to vaporize. The most economical initial pressure is usually the maximum that can be developed with the type of pumping equipment available, or that can be safely carried by commercial pipe. These values, too, will be known in advance by the engineer, or may be obtained from the manufacturers. Generally speaking, then, the only variable factors in pipe line design for a given set of conditions will be the diameter of the

line and the spacing of the pumping stations. These are inter-related factors; that is, by using larger sized pipe, we may reduce pressure loss in the line and thus increase the distance between pumping stations. The engineer must balance the cost of the larger diameter pipe against the cost of a larger number of pumping stations, determining with one or another of the formulas for calculating pressure loss, the size of pipe and spacing of pumping stations that will give the lowest capital cost. The operating cost of the line after completion enters also as an important factor. For example, it may happen that the saving in operating expenses, due to the elimination of one or more pumping stations, will warrant the expenditure of a greater capital investment in the provision of larger sized pipe, which would make reduction in the number of pumping stations possible.



(*After H. W. Crozier in Journal of Electricity*).

FIG. 318.- Curves illustrating graphic solution of an oil pipe-line problem.

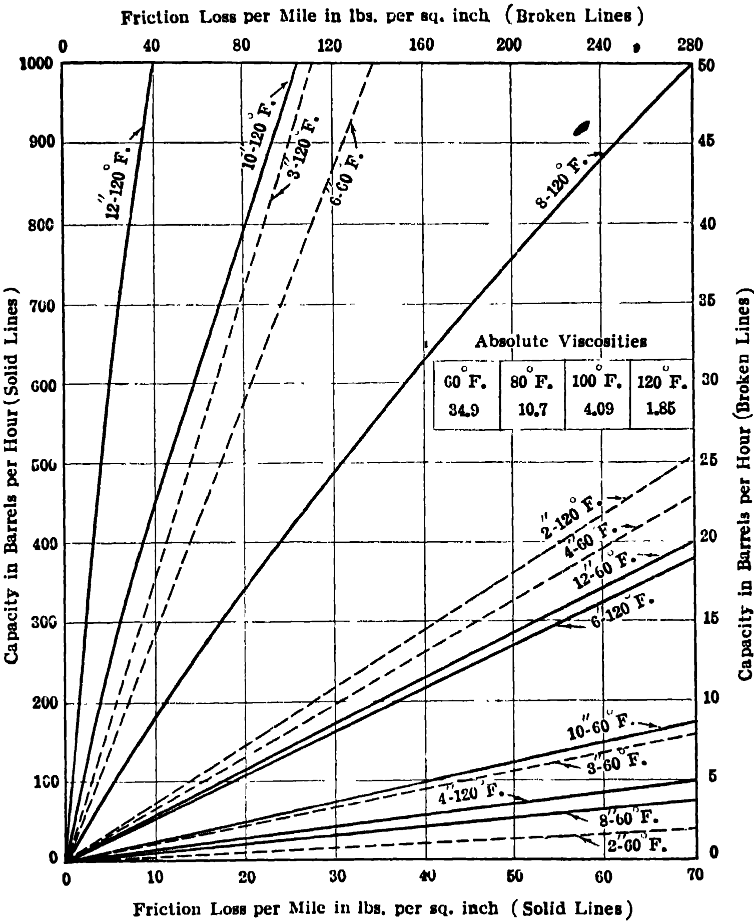
Graphical Solution of Pipe Line Problems.—A convenient method of studying the effect of the different variables involved in pipe line design is that suggested by H. W. Crozier[1] (see Fig. 318).

A graph is first constructed, based on an assumed initial temperature for the oil pumped, which indicates the temperature of the oil at all distances from the pumping station up to a distance greater than the maximum possible spacing of pumping stations. This curve we will call the "temperature decrement curve." Points on it may be determined by application of formula (5) above.

A viscosity temperature curve for the oil to be pumped is next developed by making tests with a viscosimeter and plotting the viscosities against their corresponding temperatures. Knowing the viscosity of the oil to be pumped at all temperatures, by reference to the temperature decrement curve, we next develop a graph representing the viscosity of the oil at various distances from the pumping station. This we may call the "viscosity increment curve." It is plotted on the same sheet of coordinate paper as the temperature decrement curve, and to the same abscissa scale. The viscosity increment curve, of course, will be of ascending characteristics, the viscosity

increasing as the oil attains greater distance from the pumping station, due to the decrease in temperature.

By the application of either of formulas (2), (3) or (7) given above, we may, knowing the viscosity of the oil at varying distances from the pumping station, determine the corresponding pressures in the line at the same distances. Connecting these points with a smooth curve, we have a means of predicting the pressure in the line at any distance from the pumping station. This graph we may call the

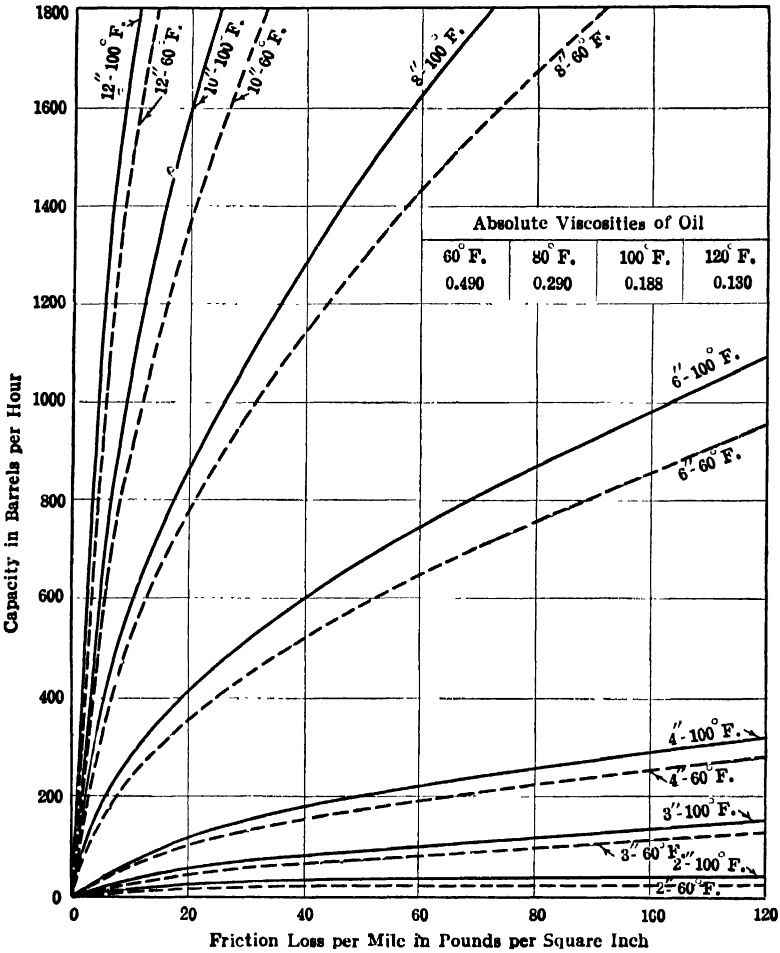


(*After Standard Oil "Bulletin"*)

FIG. 319.—Flow curves for use in oil pipe line computations. For 15.2° Baumé California oil.

"pressure decrement curve." It has the same significance as the "hydraulic gradient line" commonly employed in graphical solutions of problems in hydraulics, but differs from an ordinary hydraulic gradient line in that it is a curve instead of a straight line. This is due to the influence of changing temperature, resulting in increased viscosity. Where the pressure decrement curve crosses the abscissae representing zero pressure, we have indicated, by projection to the horizontal scale representing distance from the pumping station, the maximum spacing of pumping stations permissible under the given conditions.

This assumes that the two stations are on the same level, which, however, will seldom be the case. To correct for differences in elevation, we have merely to construct the profile of the line in terms of equivalent pressure, and the intersection of this "pressure profile" with the pressure decrement curve shows the maximum spacing of pumping stations on the particular profile.



(*After Standard Oil "Bulletin"*).

FIG. 320.—Flow curves for use in oil pipe line computations.
For 24.4° Baumé California oil.

Fig. 318 shows the solution of a typical problem, from which—as shown by the dotted lines—it would appear that the position of zero pressure on a level line is 64,500 ft. (or 11.18 miles) from the pumping station where the oil is heated to 160°F., and an initial pressure of 750 lb. per square inch is impressed. Points on the pressure decrement curve are in this case calculated by means of formula (7).

Calculation of Power Necessary to Pump Oil through Pipes.—If it is necessary to determine the theoretical power requirement under a given set of conditions, we may make use of the following formula:[1]

$$\text{Horsepower} = \frac{19.2 \times (\text{gal. per min.}) \times (\text{pressure drop in lb. per sq. in.})}{33{,}000} \quad (8)$$

The actual horsepower required is obtained by dividing this quantity by the over all efficiency of the pump and power-generating equipment.

About 2 hp. will be necessary to pump 1,000 bbl. of oil per day, for each 100-lb. pressure impressed upon it by the pump.[10] This allows 15 per cent for loss between the steam cylinder of the engine and the discharge of the pump.

Use of Flow Curves in Making Approximate Estimates of Flow of Oil through Pipes.—The many tests that have been made and the large amount of practical data collected in the records of operating pipe line companies have created a fund of quantitative data on which to draw for information in the design of a new pipe line. The great difficulty generally encountered when we attempt to systematize and organize these data, however, is that of arranging them in suitable form for use. Perhaps the most convenient form for displaying such data is in the form of flow curves. Those reproduced in Figs. 319 and 320 are typical.[7]

It will be noted that there are two groups of curves, one for heavy California asphaltic-base crude of 15.2°Bé., and the other for similar oil of 24.4°Bé. There are curves given for oils at two different temperatures for each of a variety of different sizes of pipes. It will be noted also, that there is given for each of the two oils the absolute viscosities at four different temperatures.

The curves may be used for flow calculations with oils of other gravities and viscosities than those from which the curves were derived. If we wish to pump an oil of some other gravity than 15.2 or 24.4°Bé., we must first determine its viscosity at the average temperature that will prevail in the line during transmission. Then, if the oil is heavy, we can find on the curves for heavy oil, the temperature at which 15.2°Bé. oil has the same viscosity. The flow of our given oil will be the same as that of 15.2° oil at this indicated temperature. If our oil is light, we can secure the same data from the other group of curves.

An example will illustrate the method. Suppose we have an 18° fuel oil which, at the average temperature at which it is to flow, has an absolute viscosity of 1.75. From the viscosity table for 15.2° oil on the diagram for heavy oils, we find that oil of this gravity has the same viscosity at a temperature of about 121°F. Consequently, our fuel oil will, under the given conditions, flow as if it were 15.2° oil at an average temperature of 121°. The 15.2° curves can then be used for estimating the flow of our 18°Bé. oil.

Types of Oil Line Pipe and Joints

"Line pipe," a lap-welded pipe with screwed connections, using collars of heavier design than those used on ordinary "standard" pipe, has been widely used in the construction of oil pipe lines. Because of the heavier collars, line pipe will carry considerably greater internal pressures than "standard" pipe. Weights, sizes and strengths of these two grades of pipe may be compared by inspection of the figures given in Table XLIV. Standard pipe is the less expensive of the two, and may be used for low-pressure service, or even for high-pressure work in the case of the smaller sizes.

Within recent years, a number of important oil pipe lines have been constructed without screwed connections, by welding the joints with the aid of the oxyacetylene torch. Welded joints may be made as strong

as the pipe itself, and since the pipe is not weakened by the cutting of threads, it may be of somewhat lighter weight than when screw joints are used. Because of this, and since no collars or other fittings are needed, it is claimed that welded lines are cheaper. If the welding is properly done, welded lines are also more secure against leakage. Expansion and contraction in lines carrying heated oil make necessary the use of expansion joints in the larger sizes of pipe, particularly above 10 in. Smaller sizes are not ordinarily equipped with expansion joints, whether welded or screwed. The welding process has been more widely used in constructing gas transmission lines than for oil pipe lines.

Pipe Line Construction

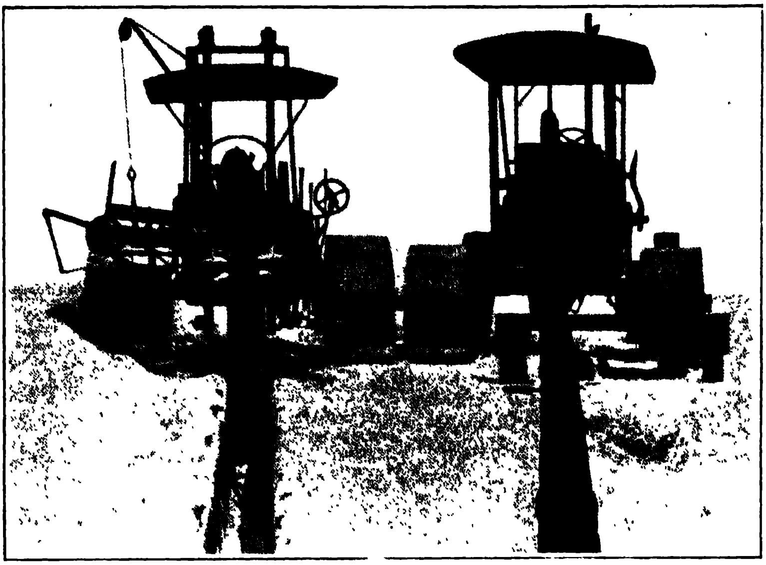
Before construction of an oil pipe line is begun, a careful survey of the route to be followed will be made. This will include the measurement of distances and elevations and the setting of stakes marking the route to be followed. Special attention will be given to the topography traversed, the condition of the soil and stream crossings. The necessary steps to secure a right-of-way for the line and title to such land as may be required for pumping stations and tank farms will also be completed before construction work is undertaken.

Accessibility will be an important consideration in selecting the route for an oil pipe line. The delivery of pipe and construction equipment, supplies for construction camps and facility in subsequent repair and inspection of the line, require that the route be accessible to wheeled vehicles, preferably railroad or motor truck transportation. For this reason, pipe line routes are often selected paralleling a railroad right-of-way or some main highway.

The first consideration in the actual construction of the line will be the distributing of the pipe along the route selected. Pipe delivered from the steel mills in carload lots will be unloaded at near-by railroad stations or sidings and loaded into horse-drawn wagons or motor trucks used in "stringing" the pipe along the right-of-way, care being taken to unload just the proper number of joints per mile so that there will be neither a shortage of pipe nor a surplus when the joints are coupled together.

After the construction equipment has been assembled and the necessary workmen organized into crews, work will be begun at one end of the the line or in some cases, a start will be made at the middle, working with a separate crew toward each end. The work of laying the pipe involves several operations, each performed by a different crew of workmen and with different equipment. The major operations involve: (1) excavating the trench, (2) screwing or coupling the pipe, (3) painting or coating the pipe with protective covering, (4) lowering the pipe and "staggering" it in the trench; and (5) backfilling the trench.

Trenching may be accomplished either by hand, using pick and shovel methods, or with the aid of a trenching machine. The mechanical method is more rapid than the hand method, and the trench is excavated at a lower cost per linear foot. Trenching machines are commonly of the self-propelling or tractor type, using a gasoline engine as motive power, and excavation of the trench is accomplished by a large revolving wheel equipped with scrapers or buckets around its circumference (see Fig. 321). The size of the trench must vary with that of the pipe. The trench for an 8-in. pipe is 20 in. wide and from 2 to 3 ft. deep. In cold climates or at high elevations where frost and low ground surface temperatures may become important factors in heat radiation losses, the trench may be made deeper, say 4 ft.



(Buckeye Traction Ditcher Co., Findlay, Ohio)

FIG. 321.—"Buckeye" traction ditching machine (left) and pipe-screwing machine (right).

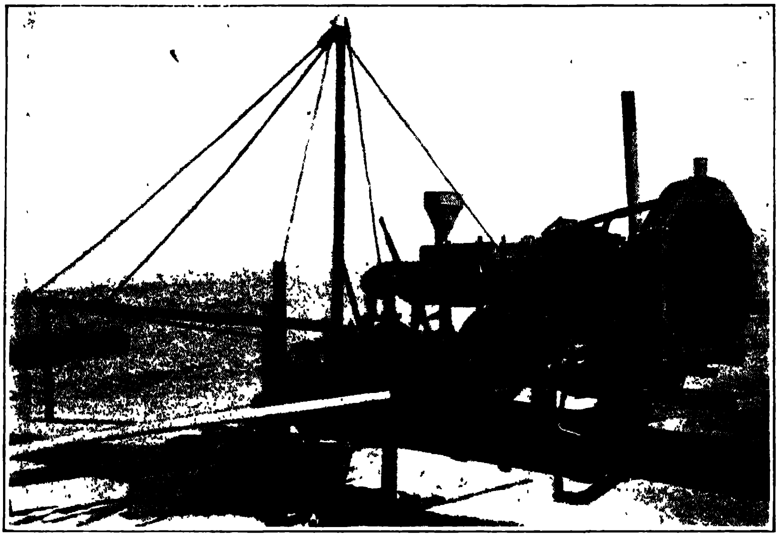
Using Buckeye Traction ditching machines,* it has been found possible to excavate as much as 2,600 lin. ft. of trench, 22 in. wide and 3 ft. deep, in one 10-hr. day. The average capacity, however, for this size of trench is from 1,600 to 2,000 lin. ft. per 10-hr. day. Progress naturally varies materially with the character of the soil. Under unusually favorable conditions, in trenching for an oil pipe line near Caspar, Wyo., 7,800 ft. of trench, 42 in. deep and 20 in. wide were excavated in 24-hr. Operating costs are said to range from $17 to $50 per 10-hr day, depending upon the size of the machine and the cost of labor and fuel.

Screwing the Pipe.—The pipe, as shipped from the mill, is in random lengths averaging about 20 ft. A pipe collar or coupling is securely screwed on one end and a rough collar on the other end protects the threads during transportation. Just prior to placing a joint in the line, this thread protector is removed and the threads on the exposed end of the pipe and within the collar are carefully cleaned with oil or pipe "dope." This reduces friction in screwing the joints together, protects the threads against corrosion and facilitates repairs or salvaging the line at some future time. A swab consisting of a disc made of leather or rubber belting fastened on a metal rod or

* Manufactured by Buckeye Traction Ditcher Co, Findlay, Ohio.

small pipe, or a disc-shaped wire brush, of the same size as the inner diameter of the pipe, is drawn through each length of pipe to remove dirt and mill scale.

When hand methods are used, the lengths of pipe are screwed together while resting on skids placed at intervals across the trench. Each length is carried to its position by men equipped with pipe-carrying tongs and bars. One member of the gang, called a "stabber," starts the threaded end of the length of pipe into the open collar of the preceding length, revolving the former by hand for a few turns to make certain that the threads are not crossed. Other men are meanwhile engaged in placing "pipe jacks" and "jack boards" under the pipe to hold it in alignment during the



(*Courtesy U S Bureau of Mines*).

FIG. 322.—Mahoney pipe-screwing machine operating on eight-inch pipe.

screwing process. After the new length of pipe has been fairly started in the collar by the stabber, snubbing ropes are applied for further screwing, and finally metal pipe tongs are used to tighten the joint. A crew of 70 men can clean, lay and apply protective paint and covering to about 3,000 ft. of 8-in. line per day, using hand methods.

Pipe laying is more rapidly and economically accomplished, particularly in the case of the larger sizes, with the aid of a pipe screwing machine, requiring the services of from 15 to 30 men (see Figs. 321 and 322). There are two general types of pipe laying machines available: (1) the Buckeye machine, which is mounted on a caterpillar tractor, the pipe being laid from the back of the machine; and (2) the Mahoney machine, which travels on the pipe.

The Mahoney machine was the pioneer pipe laying machine. It was developed during the laying of a 170-mile California line, and has since been successfully applied in the laying of a number of important lines in the mid-continental and gulf coast region. This machine grips the pipe with the aid of a set of pipe tongs mounted on the inner circumference of a rotating steel cylinder. Power is applied from a gas engine through gearing. The entire machine is mounted on a tubular frame which surrounds the pipe and rests on it. Small traction rollers are provided within this frame for moving the machine along the pipe under its own power. A pair of legs or spuds,

actuated by power-driven gearing, provide means of raising or lowering the machine and the pipe on which it travels. With the aid of a small crane and power-driven hoist, also a part of the machine, a length of pipe may be picked up from the ground, hoisted and swung into position, and rapidly screwed into the collar. The operator rides on the machine within easy reach of all the necessary gears, clutches and control levers. The machine is also able to make bends in the pipe when desired. In making bends in the pipe, it is desirable to maintain a radius of curvature of not less than 150 ft. As much as 11,740 ft. of 6-in. pipe have been screwed with one machine during a 9-hr. day. This time included the making of 28 bends. The best performance with 8-in. pipe is about 8,700 ft. per day, and with 10-in. pipe, 8,200 ft. per day.

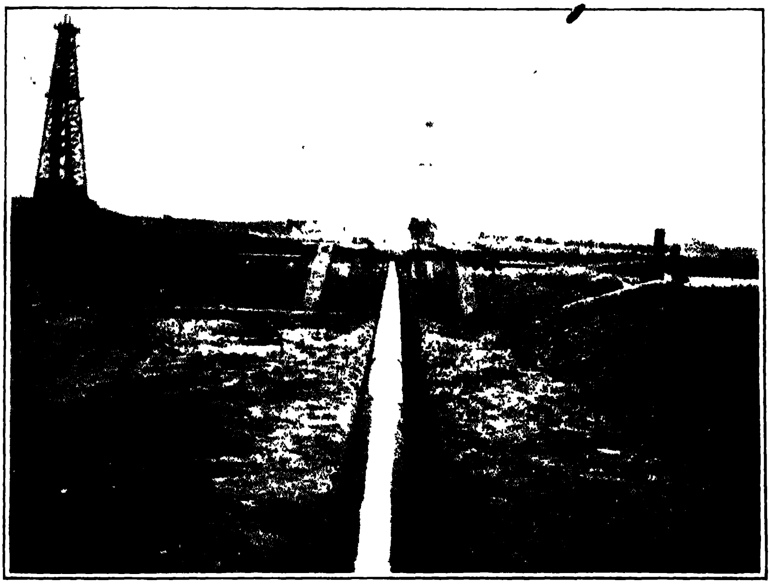


FIG. 323.—Eight-inch pipe suspended from horses, ready to be lowered into trench.

Applying Protective Covering.—The pipe, after screwing, is lowered on wooden skids placed at intervals across the top of the trench. With the pipe in this position, a protective coating is applied. This is necessary to prevent corrosion of the pipe, particularly in alkaline soils or where saline ground waters are prevalent. The protective coating may consist of a coat or two of asphaltic paint or enamel, or of roofing paper, roofing felt or burlap wired and wrapped around the pipe and saturated with hot asphalt. Before applying the protective coating, the pipe must be carefully cleaned and scraped to remove dirt, blisters and mill scale. The protective material may be applied by hand methods, using large brushes, or it may be poured on the top of the pipe and spread with the aid of a strip of canvas or "sling," passed under the pipe and drawn back and forth by two men, one at each end. In several recently constructed pipe lines, the protective coating has been applied by machines developed especially for the purpose. One such machine, used on a California line, traveled on wheels resting on the pipe, and was provided with a rotating brush and scraper for removing dirt and mill scale and rotating brushes for applying the enamel or paint. A 6-hp. gas engine mounted on the machine furnished the necessary power for revolv-

ing the brushes and scraper. The machine also carried tanks containing the molten enamel and water and fuel for the engine. Coating operations, conducted either by hand or machine methods, require that the pipe be lifted off the skids at points where painting is in progress. This is readily accomplished with the aid of a long lever mounted on wheels, or by means of wooden horses straddling the pipe and equipped with rope or hose-covered chain slings (see Fig. 323).

Lowering Pipe in Trench.—After the protective coat has hardened, the pipe must be lowered into the trench. This is accomplished, after the skids have been removed, with the aid of the above-mentioned horses or with a tripod which supports a small handpower winch. The pipe is then pried to alternate sides of the trench at about 100-ft. intervals, so that it occupies a zigzag position in the bottom. The trench is also partly filled with earth at the same intervals to maintain the pipe in this position until such time as the trench can be entirely filled. The purpose of laying the pipe in this manner is to provide for expansion and contraction in the line which may be a serious factor because of the variable temperatures to which it is subjected.

Backfilling completes the work of laying the pipe, removing the loose material which has been left standing in a pile along one side of the trench, and placing it back in the trench. The excess earth is piled over the filled trench. This work may be done by handshoveling, or with the aid of horse-drawn road scrapers, but is more economically and expeditiously accomplished with the aid of backfilling machines developed for the purpose. Such machines are usually of the self-propelled, tractor type, and travel along, straddling the dirt pile. The earth-moving mechanism consists of a series of flat scrapers attached to chains which travel transversely to the ditch and move the material from the pile to the trench. A simpler device consists of a diagonally placed scraper attached to a small tractor.

Stream and Road Crossings.—Bridging is often resorted to where a small ravine, stream or marsh, or a railroad cut is to be crossed. For this purpose, a simple trestle is usually constructed, or a cable suspension for the pipe is provided. The pipe is preferably enclosed in a rectangular wooden box in such cases, with oil sand or other heat-insulating material packed about it. In crossing a road, the pipe should be buried at somewhat greater depth than elsewhere, in order to avoid any possibility of its becoming exposed by ruts or washouts, and to prevent it from being subjected to undue vibration or wheel pressure from passing traffic.

In crossing rivers where no trestle or other supporting structure is possible for the pipe, it must be laid directly across the stream bed and submerged. In such places, it is customary to place a "river clamp" at each joint to add weight to the line and to reinforce the coupling. The river clamp is a heavy cast-iron split clamp, the two halves of which may be securely bolted together over the pipe collars. In order to give additional security against the line parting due to the pressure of water flowing over and around it, it is customary to arch the pipe upstream, anchoring the shore terminal and approaches with concrete blocks and long metal bars called "river dogs," which are driven into the earth on the downstream side of the pipe. Some operators prefer to weld pipe at stream crossings, particularly where shifting sands may leave long sections of the pipe without support. However, the difficulty of making repairs to a welded stream crossing in case of a break is obvious.

Sea Anchorages.—Along the Gulf Coast of Mexico, sea-loading anchorages have been developed, at which tank ships are loaded 1½ miles off shore, while riding at anchor, from pipe lines laid on the ocean bed. The pipe lines are constructed on land, and dragged out to sea and lowered with the aid of a ship. At the outer end, the pipe is anchored to prevent movement, and is equipped with a flexible hose connection, supported at the surface by a fixed buoy. Tank ships anchored near by establish hose connections with these subterranean pipes and receive their cargo directly from tank storage on shore.

The pumping stations along an oil pipe line are generally standardized. Since the stations are usually spaced at approximately equal intervals, the equipment for all stations on the same line may be practically identical. The pumping station must be designed throughout to meet the

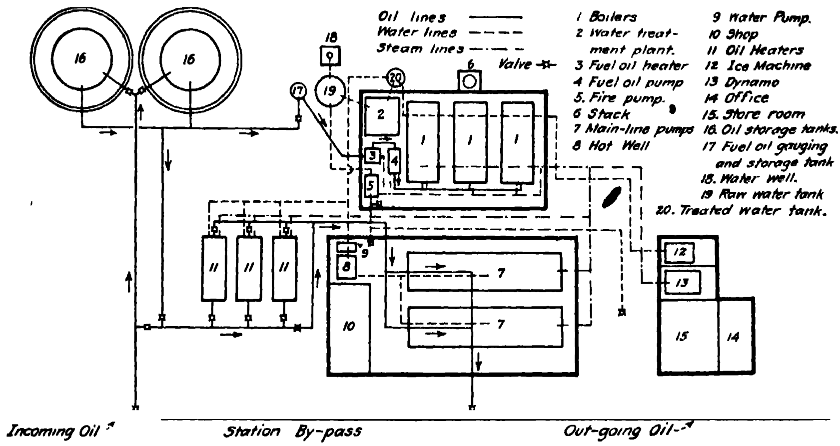


FIG. 324.—Diagrammatic lay-out of a typical steam-driven trunk pipe line pumping station.

FIG. 325.—A typical California pumping station.

peak load imposed by the transmission of the desired volume of oil under the most unfavorable conditions. Such conditions usually coincide with the coldest season of the year when temperature radiation losses from the heated oil in the pipe line are at a maximum.

The design of the station will depend to a large extent upon the type of power adopted. Oil being the most readily obtainable fuel, it is almost

universally used as a source of power. In the case of pipe lines engaged in transporting the lower grades of petroleum, steam power developed by burning the oil under boilers is commonly used, but in cases where the oil is too valuable to burn as fuel, it is applied more efficiently in the Diesel or semi-Diesel type of oil engine.

If steam power is used, the pumping station equipment should be housed in two separate buildings, one for the power plant, and the other for the pumping units (see Figs. 324 and 325). This is necessary chiefly because of the fire risk, and fireproof construction should be followed throughout. There may be, in addition, a gate house in which the valves and manifolds for controlling the flow of oil in the pipes leading to and from the station and the storage tanks are placed. Oil and water tanks are located outside of the buildings, the former at a safe distance. The oil heaters, too, are often placed outside of the station buildings, but near the pumps.

In the case of a typical California pumping station equipped for steam power and operating on an 8-in. pipe line having a capacity of about 25,000 bbl. per day, the main plant units at each pumping station consists of the following:[2]

1. Two 250-hp. water-tube boilers, placed in a brick setting with fireboxes arranged for burning fuel oil, together with the necessary auxiliary pumps and heaters for the fuel and feed water; hot wells, etc.

2. One main pumping unit, consisting of 26- and 42- by 36-in. horizontal, cross-compound Corliss steam engines, direct-connected by cross-yokes and side rods to a four-plunger, 6½- by 36-in. cast-steel oil line pump, capable of pumping 1,200 bbl. of oil per hour against a pressure of 800 lb. per square inch.

3. One 16- and 30-in.—7½- by 24-in. horizontal duplex, compound, direct-acting oil pump for auxiliary service, capable of pumping from 12,000 to 15,000 bbl. of oil daily at 800 lb. per square inch pressure.

4. Two (or more) cylindrical oil heaters equipped with steam coils of adequate heating surface to heat 1,200 bbl of oil per hour from 60 to 160°F. Exhaust steam from the pumping engines is used for heating the oil.

5. Two 37,500-bbl. steel oil tanks for oil storage. Storage is essential at each station to take care of the incoming oil in case repairs involving a brief interruption in pumping service are necessary. A 1,200-bbl. steel tank for the storage of boiler feed water, and two 100-bbl. tanks for gaging and storing oil used for station purposes will also be needed.

6. Incidental equipment: A dynamo for electric lighting; an ice machine; shop, tool and repair equipment; fire and general utility pumps; bridge crane to facilitate repairs over pumps and engines.

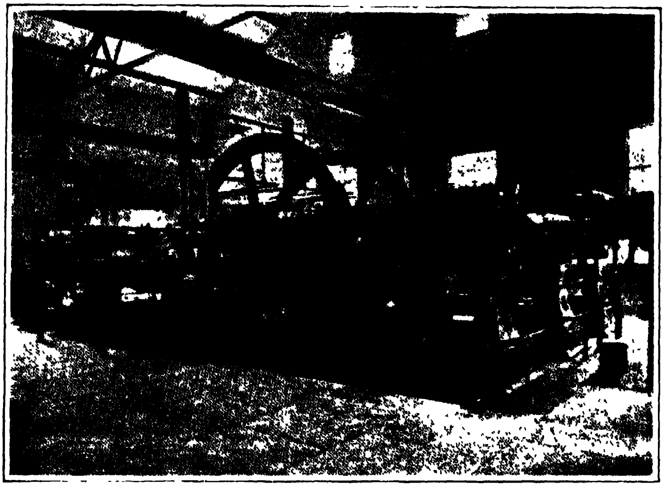
7. Buildings: Galvanized iron, wooden frame buildings are suitable, though if it appears that the field which the pipe line serves will be productive over a long period of years, a more permanent type of building of brick with concrete floors may be warranted.

When a station is equipped with oil engines, no steam-generating equipment is, of course, necessary, and the design of the pumping plant is much simplified. Oil engines of the Diesel and semi-Diesel type have been widely and successfully used in equipping most of the recently built pumping stations in the mid-continental and gulf coast region. Both two-cycle and four-cycle engines, and engines of both the horizontal and vertical types are in use, but the four-cycle horizontal engines are becoming increasingly popular. The following are typical installations:[9]

1. A pumping station on the Texas Company's line at Sour Lake is equipped with four 150-hp. Snow engines, each geared directly to 8¾- by 12-in. Gould vertical triplex pumps. Each pump has a capacity of 350 bbl. per hour. They are designed to operate at about 75 per cent of their rated power output, and are geared directly to pumps of either the vertical triplex or horizontal duplex type. The initial pipe line pressure applied varies from 350 to 700 lb. per square inch.

2. In the same district, the Magnolia Petroleum Company uses De La Vergne 100- and 150-hp. engines, direct geared to National Transit vertical triplex and horizontal duplex power pumps. The Hull Station, owned by the Magnolia Company, which contains three 150-hp. units and three 100-hp. units is reported to operate on from 8 to 10 bbl. of fuel oil per day.

Further description of oil engines of the type used in pumping service will be found in Chap. XIV.



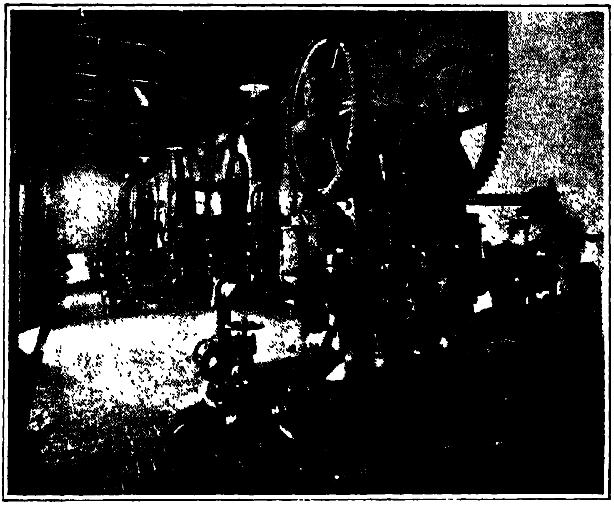
(*From U. S. Federal Trade Commission's Bull.*)

FIG. 326. -Horizontal pumping unit, Wood Station, Oklahoma Pipe Line Co.

The pumping units employed are usually of the horizontal, reciprocating piston type, with outside packed plungers, though vertical pumps are giving satisfactory service on some mid-continental lines. The design will naturally vary somewhat with the type of power used. The steam-driven pump will be found more flexible in meeting variable speed and power requirements, but consumes nearly twice as much fuel as a direct-connected Diesel engine installation, even though a triple-expansion steam engine is used. The pumps should have large valve openings, particularly if they are to handle viscous oils. Figures 326 and 327 illustrate typical pumping units for main trunk line service. That illustrated in Fig. 326 moves 1 bbl. of oil with each stroke.

Telephone System.— In order that there may be an adequate means of prompt communication between different pumping stations and other points along the line, a telephone line is constructed paralleling the pipe line. Permanent telephone sets are provided at each pumping station, and portable sets may be connected with the line at any desired point. Such a means of communication is practically a necessity from the

standpoint of security in operation of the pipe line, and is a great convenience to the station attendants, line walkers and oil dispatchers in communicating with each other. The pipe line operations are usually controlled by a dispatcher located at the field end or at the initial pumping station, who is in communication at all times with every station along the line.



(From U S Federal Trade Commissions Bull)

FIG. 327.—Vertical cylinder, triplex power pumps, Grayson Station, Gulf Pipe Line Co.

Testing the Line.—After completion of a new pipe line it is customary to subject it to certain tests before it is placed in service. A "go-devil," or scraping device, is pumped through the line to make certain that it is clear of obstructions. Each operating division, in turn, is tested for leaks and defective joints, by filling the pipe with water and applying pump pressure somewhat in excess of that at which the line is to operate.

Pipe Line Operation

The determination of the most efficient operating conditions requires a close study of all factors involved, so that a reasonably uniform performance will be maintained at each station. Since variation in the type of oil pumped may seriously alter the viscosity-temperature relationships, and hence the pumping pressures and delivery volume, an effort is made to keep the oil carried by a particular line as uniform as possible. In cases where the field which the line serves produces several different grades of oil of differing market values, this may be a difficult matter if there is only one pipe line. Usually, however, particularly if the

market values are not influenced by differences in gravity, it will be possible to secure practical uniformity in the oil handled, by blending. In any case, it should be possible to handle the various grades in "runs" of 100,000 bbl. or more so that operating conditions will not be continually changing.

Because of the irregularity in flow conditions within the pipe, it is impossible to maintain separate "runs" without a certain degree of admixture during transmission. This, however, in the case of 100,000-bbl. runs, should not influence more than about 10 per cent of the oil pumped.

Since the radiation losses from the heated oil will normally be greater in winter than in summer, the capacity of the line under a given set of operating conditions will be greater during the warmer season. Variations in temperature losses may be offset, however, by varying the initial temperature or the pumping pressure. Greater initial pressure may be secured by operating the pumping unit at higher speed, or by bringing auxiliary pumping units into service.

Continuous operation of the line without interruptions in service is an important factor in securing operating efficiency. The greatest load is encountered when pumping is resumed in a pipe line after an interruption in service. At such times oil at rest in the pipe has had time to cool until it approximates prevailing ground temperatures. On resuming operations, the pumps must for a time work against the resistance of a long plug of viscous oil which will greatly reduce capacity until the lines are cleared and normal operating temperatures are secured. Under such conditions, an auxiliary pump, which can be operated in series with the main pumping unit, will be of great assistance.

Prior to shutting down a pumping division, some pipe line operators pump hot water into the line until all the oil has been forced out.[9] This water can be readily moved when it is desired to resume operations, first pumping heated water until normal operating temperatures are attained in the line, when the pump suctions are switched from water to oil.

In dealing with heavy viscous crudes, it is desirable, from the standpoint of efficiency, to operate the line at as near full capacity as possible. A rate of flow of at least 3 ft. per second will be desirable in such cases. Operating pressures and power consumption may actually be greater at low speeds and capacities than at full capacity, due to the greater time for heat radiation in the former case. Experienced operators will move "runs" of heavy crudes through the lines at high speed even though the pumping equipment must be forced to accomplish the more rapid transmission.

The labor employed at a typical California pumping station on an 8-in. pipe line handling a maximum of 25,000 bbl. of oil per day involves the services of eight men working on 8-hr. shifts or "towers," one boiler

attendant and one pump room attendant on each shift, and a foreman and gager working only one of the three shifts.

Looping.—When an existing pipe line is no longer sufficient in capacity to meet the demand put upon it, a situation which often develops when the field served by the line suddenly increases in productivity, an expedient called "looping" is sometimes resorted to for the purpose of increasing the carrying capacity. This consists in laying and connecting several miles of additional pipe, parallel and connected at intervals with the original line.

In eastern United States practice, handling constant-temperature oil, it makes no difference whether the loop is cut in at the pump end of a pumping division, or the terminal end; but in cases where the oil must be heated to facilitate flow, it makes a material difference. The loops should in the latter case be constructed at the terminal end and not at the pump end. The reason will be readily apparent when it is remembered that the loss of heat is proportional to the radiating surface of pipe exposed to the earth, and is a function of the difference in temperature between the oil and the earth; therefore, if the loop is installed at the head or hot end, the heat loss will be greater and the average temperature lower. Furthermore, the added capacity is of greater advantage where the oil is colder and the viscosity greater.

Using two different sizes of pipe in the construction of a single pipe line is another device for reducing pressure loss and increasing capacity, and is a very useful method of obtaining a desired result at the lowest expense, particularly in original construction. In handling heavy oils, considerable economies in construction are realized by using larger pipe at the receiving end of each pumping division, where the oil is colder and therefore more viscous. For example, in the case of a pipe line built in California, by using 10-in. line pipe on the latter third of each pumping division of an otherwise 8-in. line, it was found possible to space the pumping stations 1½ miles farther apart than that necessary in the case of an all 8-in. line. This resulted in the elimination of two pumping stations in a line 170 miles long and a net saving of $250,000 in the initial cost.[2]

The cost of pipe line transportation of petroleum will, of course, vary widely with the character of the oil, the size of the pipe, the form of power used and other variables.

The following figures* give the first cost of a pipe line 170 miles long, constructed in central California in 1915. Two-thirds of the line consists of 8-in.—29.2-lb. line pipe, and one-third is 10-in.—41.6-lb line pipe. There are eleven pumping stations along the line, the main equipment comprising 22—250-hp. Heine boilers, eleven high-duty, crank-and-flywheel-type oil pumping engines, eleven auxiliary direct-

* U. S. Federal Trade Commission, "Report on Pacific Coast Petroleum Industry," Pt. I, 1921.

acting oil pumping engines, twenty 37,500-bbl. oil tanks, eleven 1,200-bbl. water tanks and eleven steel buildings.

COST OF A 170-MILE CALIFORNIA PIPE LINE

Item	Amount
Land	$ 42,395.44
Rights-of-way	97,159.74
Line pipe	735,498.78
Line pipe fittings	29,757.12
Pipe line construction	531,919.36
Buildings	362,167.33
Boilers	130,192.78
Engines and pumps	372,708.37
Water supply	141,632 07
Electric wiring	9,528.23
Miscellaneous and tanks	22,783 95
Piping	185,579.68
Auxiliary machinery	146,461.36
Oil tanks	295,492.64
Delivery facilities	836.83
Telegraph and telephone lines	67,637.91
Highway equipment	18,480.91
Other property	5,084.77
Total cost	$3,195,317.27
Cost per mile	18,796 57

The pipe line skirts the foothills of the Coast Range, attaining a maximum elevation of 955 ft. The pipe was laid largely by machine methods. Transportation of material was facilitated by near-by railroads and highways. It is operated as a hot-oil line, and has a maximum capacity of about 30,000 bbl. of 23°Bé. oil daily.

The following figures show the capital cost of two other California pipe line systems:

CAPITAL COST OF CALIFORNIA PIPE LINES*

Company	Mileage	Total cost	Cost per mile	Remarks
Union Oil Company of California.	420	$9,050,140	$21,500	Built in 1917. Figures include cost of large storage facilities. 8-in. pipe.
General Pipe Line Company	212	4,930,495	23,250	Constructed in 1912. 8-in. pipe.

* These figures include the cost of pumping stations spaced at an average distance of 13½ miles.

These construction costs exceed the cost of similar development in the mid-continental fields. The average cost of building 2,196 miles of 8-in. pipe line from the oil fields of Oklahoma, Texas and Louisiana to ports on the Gulf of Mexico, has

been about $6,400 per mile, varying from $5,700 to $6,970. These costs do not include the cost of pumping stations, which averages $126,800 per station. The latter figure is the average cost of 43 stations, individual costs ranging from $83,700 to $162,250. These are prewar figures.[11]

The following figures give the operating cost for certain large oil pipe line systems in the mid-continental fields during the year 1913:

COST OF PIPE LINE TRANSPORTATION OF PETROLEUM, MID-CONTINENTAL PIPE LINE SYSTEMS, 1913

System	Thousand-barrel miles	Cost per 1,000-bbl. mile, cents
Prairie	16,844,844	15 81
Oklahoma-Louisiana	2,203,850	34.28
Gulf	4,303,902	36.29
Texas	3,928,530	39.63
Magnolia	1,671,166	44.23
Total and average	28,952,292	25.13

The following figures indicate the cost of pipe line transportation of petroleum in California:

1. The Standard Oil Company of California operates pipe lines carrying two grades of crude petroleum from the San Joaquin Valley fields to Richmond, a distance of about 300 miles. The cost varied from 14.2 cts. per barrel in 1914 to 21.3 cts. per barrel in 1919, for light oil (about 24°Bé.); and from 15.4 cts. in 1914 to 23 cts. per barrel in 1919, for heavy oil (15°Bé.).
2. The Associated Oil Company operates an 8-in. pipe line from the San Joaquin Valley fields to Avon, the cost per barrel pumped varying from 11.5 cts. in 1914, to 22.1 cts. in 1919. The distance is about 280 miles.
3. The Shell Company of California operates a pipe line from the Coalinga field to Martinez, a distance of about 170 miles. The cost varied from 18.9 cts. per barrel in 1915, to 10.8 cts. in 1919. Two-thirds of the line is of 8-in. pipe and one-third is 10-in.

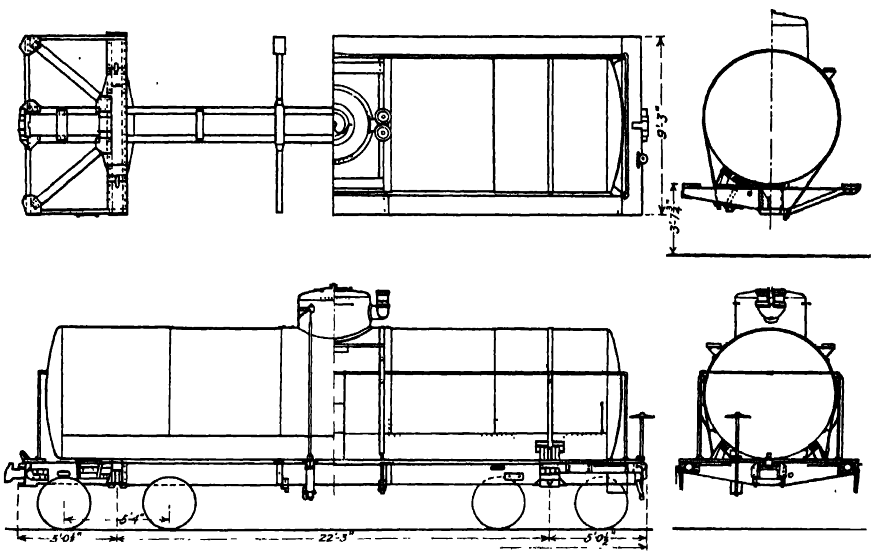
Regulations Governing Common Carrier Pipe Lines.—By law, the oil-carrying pipe lines of the United States have been declared common carriers, and as such have been placed under the jurisdiction of the Interstate Commerce Commission and the various state railroad commissions. Pipe line companies must receive oil for shipment when and where offered, but numerous restrictions are imposed which in many cases practically nullify the shipping privilege which the law is intended to convey.

In addition to numerous special regulations on different pipe lines, there are several conditions generally imposed upon pipe line shippers: (1) The minimum quantity that will be accepted for shipment varies from 10,000 to 100,000 bbl. (2) The individual shipments must be of

the same kind and gravity of oil, and impurities (sand and water) may not exceed 3 per cent. (3) Transportation companies do not bind themselves to deliver the identical oil received for shipment, but merely equivalent oil. (4) Most schedules provide that a pipe line company may deduct 2 or 3 per cent to cover oil lost in transit.

RAILROAD TRANSPORTATION OF PETROLEUM

As stated elsewhere in this chapter, more than 9 per cent of our domestic production of crude petroleum is transported from the fields in which it is produced by railroad tank cars. Practically all of the



(*After Railway Age Gazette and American Car & Foundry Co.*)

FIG. 328.—Elevations and plan of a typical tank car.

natural-gas gasoline and "tops" distilled from the crude in field topping plants is transported to the market centers by the same means. Since the producer shares with the railroads the responsibility of loading and preparing such products for shipment, it is essential that he be informed on the nature of the equipment used and the regulations governing this method of transportation.

Railroad oil tank cars vary considerably in size and in detail of design. Capacities range from 6,000 to 14,500 gal. The oil container consists of a horizontal cylindrical tank with cupped or spherical ends, strapped to the bed of one or another of the several types of railroad flat cars. The cylinder is substantially built of riveted or welded steel plates, designed to resist all strains to which it may ordinarily be subjected. These include not only the dead load of the oil and the stresses imposed by

the movement of the car, but in addition allowance is made for a pressure of 60 lb. per square inch which may develop within the car as a result of the vapor pressure of the liquids carried. Fig. 328 illustrates a typical design that is widely used.

Oil is charged into the tank through a connection on the turret.[10] This turret serves also to provide an air space above the main body of the oil into which the oil may expand in case it is subjected to higher temperatures than those prevailing at the time and place of loading. Gas freed from the oil during transportation also accumulates in this space and is allowed to escape through a connecting blowoff valve in case the pressure exceeds that for which the car is designed. Oil is discharged from

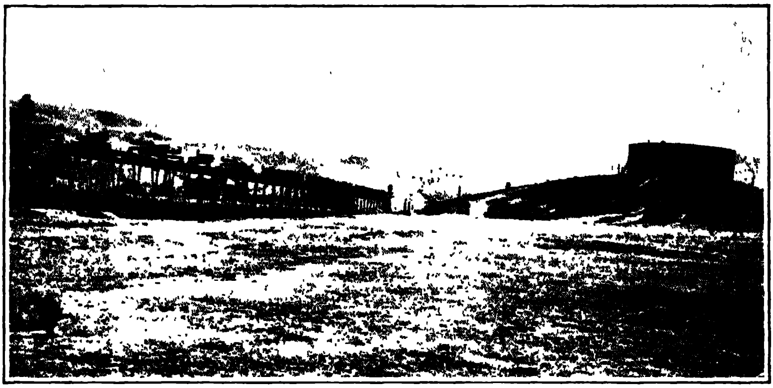


FIG. 329.—A typical loading rack.

the tank through a valve in the bottom placed either at the center or at one end. Some tanks are equipped with steam coils which may be supplied with live steam from the locomotive, thus reducing the viscosity of the oil and facilitating its discharge. Without steam equipment, the unloading of heavy viscous oils in cold climates becomes tedious.

When oil is regularly shipped in large quantities by tank car, it is customary to erect a special "loading rack" to facilitate the filling of cars. This consists of a pipe line at one side of and paralleling the railroad track, and elevated so that it is a few feet above the tops of the turrets on the cars (see Fig. 329). Connections with suitable valve controls are provided at intervals along the pipe, spaced apart to conform with the standard length of the cars. By this means, an entire train of cars may be loaded from the same pipe line at one time. Connections made of loose sleeves and elbows make possible the necessary adjustments to conform with slight variations in the position of the cars and turrets. The flow of oil into the cars may be accomplished by gravity if the storage tank connecting with the pipe line is placed on a near-by hill at an elevation above the point of discharge. If the terrain is too level to permit of this an oil line pump must be installed.

In certain regions of the United States, the cost of railroad bulk transportation of petroleum, to the shipper, averaged 3.236 cts. per ton-mile in 1920 to 1921.* Because of the high cost of rail transportation, this method of shipping is used only where pipe line facilities and waterways are not available. The method is used chiefly in distributing fuel oil and refined products to inland points by the marketing agencies; but also, to a considerable extent, by the railroads in meeting their fuel requirements.

Regulations governing the transportation of petroleum by rail have been issued by the American Railroad Association, with the endorsement of the Interstate Commerce Commission. Tank cars must be free from leaks, and all valves, dome covers and valve caps must be in good condition and provided with suitable gaskets. The car must be equipped with a mechanically controlled dome cover, which cannot open while the car is under pressure. Brakes, journal boxes, trucks and safety appliances must be in proper condition for service.

The vapor tension of the oil shipped may not exceed 10 lb. per square inch at a temperature of 100°F.; and it is not permissible to use a tank car for shipping oil that has a lower flashpoint than 20°F., unless it has been tested under a hydrostatic pressure of 60 lb. per square inch, and unless it is equipped with safety valves adjusted to operate at 25 lb. pressure. The car should not be entirely filled, a vacant space of at least 2 per cent of the total capacity being left to permit of expansion of the oil in case of temperature variation. The car must be labeled with suitable placards giving warning of the inflammable nature of the contents, and containing instructions concerning the proper method of unloading and fire protection.

WATER TRANSPORTATION OF PETROLEUM

Water transportation of petroleum is seldom a matter that concerns the producer directly, and for this reason no description of the various types of tank ships and barges used will be offered here. The producer usually has no responsibility in the loading and operation of such vessels, and has no direct interest beyond the tankage which provides the necessary storage at the shipping point, and the piping which serves to connect the storage with the piers or offshore connections. These offer no unusual problems beyond those discussed elsewhere in this volume in connection with storage and pipe line transportation of petroleum.

MOTOR TRUCK TRANSPORT OF PETROLEUM

Motor truck transport of petroleum is used by the producer only to a limited extent, particularly in moving relatively small quantities of

* American Petroleum Institute, *Bull.* 176, 1921.

gasoline or fuel oil to wild-cat wells or other out-of-the-way locations not equipped with pipe line facilities. Except in the handling of productions too small to justify the building of a pipe line, motor truck transportation is seldom feasible from the economic point of view. The cost averages about 2⁄5 ct. per barrel-mile under favorable conditions.

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CHAPTER XIX

AUXILIARY PLANTS AND DEPARTMENTS

The oil-producing property must usually be equipped with many facilities that make it practically independent of outside assistance or services, except for supplies and equipment. The employees must often live as a detached community, apart from the organized system of group service that characterizes ordinary city and town life. Both for the conduct of its direct activities in the production of oil and gas, as well as in providing for the comfort and well-being of its employees, the oil company must provide many and diverse facilities. There must be well equipped shops to care for the necessary repairs to equipment, and to fabricate and assemble much of the new equipment and tools used in the operation of the property. Buildings of various sorts must be provided to house equipment, supplies and personnel. There must be well-equipped offices, a laboratory and a drafting room to accommodate the clerical and technical staffs. Transportation equipment must be provided to facilitate the movement of men, tools, supplies and equipment about over the property. Often the company must develop its own water supply, lighting plant, power plant and telephone system. Fire protection must be given careful attention and one or more watchmen must be employed to police the property, particularly at night. For the convenience of employees living on the property, it will be necessary to erect and maintain dwellings, hotels, a store; and if the size of the community justifies, perhaps also a school, a church, a recreational center and a post-office. The officials of the company may even be called upon to exercise a paternal influence in the government and control of the working community. These varied activities add greatly to the problem of operating the property; and while apparently of minor importance, yet may be vital to success.

The shops constitute an important adjunct in the operation of an oil property. The ability to repair equipment promptly when necessary often means the saving of large sums of money. Tools and equipment must be kept in repair if the most efficient service is to be had from them. Much of the construction work incidental to expansion and replacement of worn-out plant units can be taken care of without outside help. The well-equipped oil-producing property must have its own machine shop, forge shop, carpenter shop, electrical shop, boiler shop, pipe fitting shop and tool sharpening shop. The variety of work to be done and the intri-

cate nature of much of it requires the best of equipment and highly skilled personnel. Much of it is heavy work, and the shop equipment provided must be rugged and substantial, high-powered and of large size.

The machine shop must have one or more lathes, planers, drill presses, milling machines, bolt cutters and the miscellaneous equipment of small tools to take care of an infinite variety of repair jobs. The repair and manufacture of drilling tools and tool parts ordinarily occupies a large part of the attention of the machine shop force during the development period, and in connection with the operation of pumping wells, the repair of engines, pumps and pumping equipment often requires the attention of skilled mechanics and shop facilities. If any construction work is in progress on the property, the machine shop force is apt to have an important share in it.

The forge shop is customarily equipped with gas or oil-heated forges—preferably the former—at least one being of large size, with a steam hammer for heavy forging, with suitable tempering equipment for use with large tools of special steels, and with the usual variety of anvils and small hand tools for routine forging. The forge shop force will participate in much of the repair and construction work mentioned above in connection with the machine shop, and if drilling is in progress on the property, will often be required to take care of routine tool sharpening, the dulled bits being brought from the drilling rigs to the shop for the purpose.

The pipe shop serves a useful function in the conduct of the work of the average oil-producing property, because of the large amount of pipe and casing used. The pipe shop should be equipped for cutting threads of all kinds on pipes of all sizes, and high-powered pipe-threading machines capable of handling the largest sizes of casing should be provided. There should also be equipment for cutting, bending and straightening pipe. Oxyacetylene welding apparatus will be an important part of the pipe shop equipment, since much pipe work in the oil fields is now connected with welded joints rather than screw joints. The pipe shop force may be called upon to do much of its work in the field, though the preparation of the material and machine work is necessarily done in the shop.

A large company will find it advantageous to operate its own sheet metal shop, with facilities for repairing boilers, fabricating small and moderate-sized steel oil and water tanks and other like work. Such an establishment should be equipped with high-powered sheet metal shears, punches and rolls for bending heavy plates to cylindrical form.

A timber yard and carpenter shop is often provided, with facilities for framing rig timber and other woodwork. A small wood lathe, a planer, a band saw and circular saw are useful in such a shop. There is always sufficient routine carpenter work about a property of any size to keep one or more carpenters busy, and at such times as erection of buildings, rigs,

jack-line structures and other timber work is in progress, the force may have to be temporarily augmented.

Power Plant.—The power needs of the oil producer have been adequately described in Chap. XIV, but reference should be made at this point to what is regarded as the nerve center of the mechanical plant —the central power house. The equipment of the power plant will of course vary with the type of power and form of fuel used. Steam power and gas engine power are common. In the former case, water-tube boilers fired with natural gas, fuel oil or crude oil will be employed, and every effort will be made to equip the plant for continuous and efficient service. Steam will be transmitted from this central plant through well-insulated distributing lines to the near-by wells, shops, dehydrating plant, pumping plant, natural-gas gasoline plant, topping plant or wherever steam may be needed for the development of heat or power.

Within the power house, or in a building immediately adjoining, will be placed a steam engine of sufficient size to develop power for operation of an electric dynamo, and perhaps also, gas or air compressors, vacuum pumps, water pumps, oil pumps and such other power-driven mechanical equipment as can be conveniently grouped in the central power station. Power may be transmitted from the central power plant in other ways than by steam transmission. For example, compressed air developed by the operation of air compressors within the power house may be used in operating air lifts in the near-by wells; or electric power generated in the power house may be used in operating motors in the shops, at the pumping wells or wherever small power units may be necessary. The dynamo also serves a useful purpose in furnishing electricity for lighting throughout the camp and at all rigs. In or about the power house may also be grouped various other facilities of a mechanical nature, such as the boiler water treatment plant, an ice machine, gas meters and pressure regulators, oil and gas gathering line manifolds and controls. A limited number of power house attendants employed on regular shifts may thus look after all of the mechanical equipment, which if scattered, would require the services of additional men.

If a gas engine is used to develop power in the power house, the steam plant can be dispensed with, but a steam plant is a useful adjunct in supplying heat and pressure where needed throughout the plant. Electricity purchased from an outside power company may also supplant steam power, and adapts itself satisfactorily to most purposes.

Transportation is an important element of expense in the operation of an oil property, and of considerable economic importance in the conduct of the work. Operations are often spread over a wide area. The company may operate a group of disconnected properties, some of which are several miles distant from the headquarters camp. While the more remote "leases" may be equipped with separate facilities so that they are

to a degree independent, there is always more or less transferring of equipment and supplies about from one property, or from one part of the property to another. Cleaning or repair equipment used at one well today may be needed at another well at the opposite end of the property tomorrow. There must be regular transportation service from the nearest railroad station in moving supplies from the railroad to the warehouse, and in transporting employees, baggage, express and mail. Certain company officials have occasion to move continually about over the property in inspection duties, and in visiting places where work is in progress. Gangs of workmen must be frequently shifted from one part of the property to another, wherever their services may be required.

For all such purposes, prompt and rapid transportation is invaluable, and no more satisfactory means is ordinarily available than automotive transportation. The oil company commonly operates one or more motor trucks ranging in capacity from 1 to 5 tons, for heavy trucking in moving equipment and supplies and gangs of workmen, while each official whose duties carry him into the field will be provided with an automobile of a type adapted to his needs. Some of the freight handled, such as casing, for example, is bulky and heavy, requiring a powerful truck of large capacity. Tractors are sometimes employed where roads are poor or unusually steep, or where large quantities of supplies may be moved with "trailers."

Some of the field organizations of the larger oil companies will operate from 25 to 50 or even a greater number of cars and trucks, and the aggregate daily mileage may amount to hundreds or even thousands of miles. Since the roads are often rough and the duty severe, the automotive equipment will require frequent repair and continual attention. Most oil companies of any size employ one or more mechanics skilled in the repair of automotive equipment, and a special repair shop and adequate garage facilities must necessarily be provided.

Communication between all important offices, buildings and working places is customarily by telephone. If there are a sufficient number of telephones in use, a central switchboard with an operator in attendance will be necessary. Often, however, a system of bell signals will serve in calling any of the telephones, which are then placed on a single line. The cost of the telephone system is soon repaid by the time saved in communication and by the promptness with which information may be transmitted and orders given in time of emergency. The property must also have telephonic communication with the outside world for the conduct of its business affairs, and for the general convenience of the employees. Radio telephony appears to have certain advantages for use on oil properties, particularly in establishing communication with wild-cat wells in outlying districts where ordinary telephonic communication might be difficult or costly.

Administrative Offices.—Suitable accommodations and equipment for the administrative, technical and clerical staffs must be made available. A single structure, varying in size with the number of individuals employed in such work, is usually adequate to house the office staff; and there is considerable advantage in having convenient association of the several offices, because of the close relationship that necessarily exists between them. Such an office building should provide private offices for the manager, for the various superintendents or department heads, for the chief engineer, resident geologist and purchasing agent. There must also be a large room or suite of rooms suitably equipped for the accounting, cost-keeping, stenographic and clerical staff; and a room or group of rooms for the use of the engineering department.

Equipment and Work of the Engineering Department.—In addition to the individual desk equipment, the engineering department should be equipped with drafting tables and drafting equipment; with surveying instruments, equipment for blueprinting, and perhaps also a photostat, which will be useful in making reduced size copies of drawings, maps, sections, well logs, etc. Space must be reserved for a peg model, and for the filing of maps, drawings and records.

The engineering staff will be required to assume various routine duties in addition to a great variety of special problems that may be assigned to it from time to time. Among the routine duties commonly assigned to the engineering staff will be the maintenance of graphic well logs; a peg model of all wells on the company's and surrounding properties, and the care and preparation of field and property maps and geologic sections; the tabulation and graphic recording of production records for both oil and gas, and the routine work associated therewith such as the daily adjusting of meters and the computations of gas flow from meter charts. The planning and design of new additions to plant will be carried out in the engineer's office, as well as the preparation of drawings of special tools and machine parts to be made in the shops, or in some outside foundry. Much of the work of the engineering staff will be conducted in the field—the supervision and inspection of all structural work, such as erection of buildings and tanks, the construction of roads, reservoirs, pipe lines and mechanical plants of all sorts. In addition, the engineering staff may be given the general supervision, possibly in an advisory capacity, of all drilling wells and of repair work on wells. Various investigative problems may be assigned to the engineering staff from time to time: investigations of the mechanical efficiency of various plant units, such as boiler plants, engines, compressors, pumps, etc.; investigations of the losses and extent of utilization of natural gas, and of its gasoline content; evaporation and seepage losses of oil in storage; friction losses in pipe line transmission of oil and gas; studies of methods of securing maximum recovery of oil and gas from wells—these

and an infinite variety of other special problems are presented to the engineering staff for solution.

The resident geologist is often regarded as an independent official not directly related to the engineering staff, but if the engineering staff is supervised by a petroleum engineer, as it should be for best results, the work of the resident geologist may be considered a part of the duty of the general engineering staff. The work of the resident geologist consists primarily in advising in the development work, and in making such studies of underground conditions as may be necessary in connection with the development of the property. He frequently visits each drilling well to secure first-hand information useful in compiling the well logs. Samples of the formations penetrated by the wells and of waters produced from different horizons should be preserved by the geologist in suitably labeled bottles for future comparison. He should have primary responsibility for the suitable preservation of the well logs, and will find graphic logs helpful in preparing geologic sections and structure contour maps. It should be his duty to locate new wells; to supply preliminary information on probable depth to production, and to important marker horizons; to make correlations of the strata penetrated in drilling wells; and to prescribe the positions of water shut-offs. The maintenance of a peg model will be useful in such work. The geologist may also be called upon to make special investigations on various subjects in which a knowledge and understanding of underground conditions, stratigraphy and geologic structure are important. For example, he may be required to make a detailed study of a particular group of wells which are afflicted with water incursion, in order to propose remedial measures; or he may be assigned the task of computing and valuing the oil reserves, or of studying the palaeontological and petrographic characteristics of the various formations penetrated by the wells as a means of correlating structure.

Space may also be reserved in the office building for a laboratory, though it is preferable to use a separate structure for this purpose if possible. This laboratory should be equipped with the usual instruments and apparatus employed in determining the physical properties of oils and natural gases, as well as with the ordinary chemical equipment used in routine analytical work. The laboratory staff will be required to make daily tests for water content, suspended solids and gravity of all oil samples brought in by the oil gagers (see page 473). Water samples from the wells and from the water treatment plant will require laboratory analyses. If a natural-gas gasoline extraction plant or a topping plant is operated on the property, frequent control analyses of final and intermediate products will be required. Testing of various materials purchased for use on the property, to determine whether or not they conform to prescribed specifications, may also be a part of the laboratory routine.

A portion of the laboratory, equipped with microscopic and petrographic equipment, should be reserved for the use of the resident geologist. In addition to such routine analytical and testing work, the facilities of a well-equipped laboratory will be invaluable in conducting special research on problems of importance in the operation of the property. Studies of corrosion of iron and steel casings and pipe lines, of boiler tubes and tank metals; studies of the setting qualities of cement used in cementing wells; of the properties of mud-laden fluids and their action in rotary drilling; of oil-water emulsions, their formation and dehydration; of explosives used in well shooting; of the metallographic properties and heat treatment of steel used in drilling tools—these and a great variety of other similar research problems have been receiving the attention of the field laboratory staffs of the larger oil companies in recent years.

The Accounting and Cost-keeping Department.—The work of this department is discussed in greater detail in Chap. XX. The equipment used in such work is too well known to require extended description and comment, except perhaps to point out that it is economy to provide all modern labor-saving office appliances. Loose-leaf ledgers and books for the accounting records are to be preferred to the ordinary bound variety. Card filing systems should be adopted for the primary cost records and related records, and substantial and conveniently arranged filing cabinets should be provided. Typewriters should be of modern type, with wide carriages, tabulating devices and equipped with special characters and symbols for engineering work. A dictating machine will be useful. Calculating machines are invaluable in performing computations in connection with the accounting, cost-keeping and time-keeping records. A mimeograph or other duplicating machine will be useful in preparing duplicate copies of reports, cost records, notices and instructions to employees, etc. Files for correspondence, reports and records of all sorts must be of ample capacity, suitably arranged and adapted to their intended purpose. An office safe or vault for the storage of valuables, and preferably of sufficient size to receive the principal books of record and other valuable documents, is a practical necessity.

The Personnel Department.—A comparatively recent development in the management of oil properties is the establishment by some of the larger companies, of personnel departments, charged with the duty of regulating industrial relations with their employees. To the personnel department is entrusted the engaging of all employees, the maintenance of personnel records and rating of employees for promotion. The fostering of friendly relations between the company and its employees, the planning and supervision of industrial welfare work and the prevention of accidents through education and "safety first" propaganda are among the other duties of the personnel department.

A typical organization of this type maintains a field office at which all individuals seeking employment make application. Each applicant is required to give full particulars concerning his experience, education, age, nationality, previous employment, etc., and to give oral or written answers to a group of questions designed to test his knowledge of the particular occupation which he seeks. Each applicant is rated on the basis of this test and on his personal record, and in filling vacancies the individual having the highest rating in his particular classification is selected. Before entering the employ of the company, the applicant must pass a physical examination administered by the company's physician, to determine whether or not he has any organic disease or is otherwise physically unfit for his selected occupation. The company operates a vocational training school in which employees may, if they so desire, receive instruction in technical courses designed to increase their knowledge and usefulness in their various occupations. Grades assigned in these courses, and ratings given by the foremen and superintendents every 6 mo., provide the basis for occasional reclassification of employees. Promotions and salary increases are based largely on periodical personnel ratings. If an employee has a grievance or desires a change of occupation, he takes the matter up with the personnel department, which is supposed in such matters to occupy a judicial position between the management and the employees. A foreman or superintendent, wishing to discharge an employee from his department, notifies the personnel officer, who may either sever the individual's connection with the company, or offer him employment in some other department, as the circumstances may warrant.

Every effort is made to reduce accidents and illness among employees by educational work of various sorts. Prizes are offered for "safety first" suggestions. Competition is stimulated among the several departments and working groups to secure the lowest accident rate. Occasional group meetings are held at which accident prevention in general is discussed, specific accidents being analyzed by individual demonstration or with the aid of motion pictures. At such meetings also, employees are given instruction in first-aid, sanitation and personal hygiene. The company provides a well-equipped hospital with a physician and nurse in attendance at all times.

In many cases also, the personnel department is expected to take the initiative in organizing the social activities of the community. Competitive sports are fostered. Club rooms and reading rooms are provided by the company and supervised by the personnel department. Many of the larger companies publish monthly magazines with the purpose of fostering loyalty among the employees, and a better understanding of industrial relationships. Regulations with respect to sick benefits, accident indemnity, retiring pensions, vacations and other similar

welfare provisions may be conveniently administered by the personnel department; and the company may through this organization find a means of promoting more substantial welfare work among its employees by interesting them in the purchase of homes, insurance, or of the company's stocks and securities on some cooperative basis.

The personnel department should be provided with adequate quarters, but for psychological reasons it is better that this office be somewhat apart from the other administrative offices. The department can best serve its intended purpose if it has the full confidence of the employees, and an effort should be made to cultivate the idea that it represents their interests rather than those of the management. The department is presided over by a personnel officer, selected primarily for his ability as an organizer and for personal leadership. This "point of contact" between the company and its employees is an important one, and care should be taken in the selection of the man to fill such a position.

Technical Library.—For the use of the technical and administrative staff, it is desirable that the company should maintain a technical library containing the better known reference books on petroleum technology, geology, chemistry and general engineering. Files of government publications on petroleum technology and geology, transactions and bulletins of the technical societies, statistical reports on the oil industry, trade catalogs and technical journals, will also be useful. Some of the larger oil companies, in their headquarters libraries, have found this work of sufficient importance to justify the employment of a librarian, who is required to index carefully and file all technical and statistical material bearing on the oil industry, and to prepare bibliographies and technical reports on specific subjects when requested to do so.

The Store House and Related Appurtenances.—On the average, about 25 per cent of the cost of producing petroleum is represented by supplies and equipment consumed in the work. The sums annually expended for materials are therefore large, and the care and distribution of them becomes an important aspect of the business of oil production. Every article, no matter how small, represents money, and should be given the same care and attention as though it were actual cash. Banking principles are applicable to stores as well as to money. Every item of merchandise is charged against the store house when it is received, and the storekeeper is held responsible for it until it is issued on a requisition signed by some authorized individual.

Proper care of stores requires that a suitable warehouse be provided, with protection against theft and exposure to weather. The warehouse should be a long, one-storied structure, surrounded by a platform on all sides, and with large sliding doors on the sides so that material unloaded on the platform can be trucked directly into the building without turning corners. For convenience in handling heavy freight, the warehouse

platform should, if possible, be on the same level as that of the bed of the truck, wagon or railroad car in which material is delivered or removed. In some cases arrangements are made for driving motor trucks directly into the building, so that the unloading platform may be under cover. In this case an overhead traveling crane will be useful in moving heavy equipment directly from the delivery truck to its place of storage. Within, the warehouse is equipped with suitably arranged tiers of shelving, bins or racks for the storage of the stock. In addition, open floor space must be reserved for the storage of unusually heavy or bulky objects, and there must be ample aisle space for trucking materials to and from their place of storage. A systematic arrangement of stores should be worked out which will bring all similar or like articles together, and those in greatest demand should be most accessible.

The storekeeper, who is made responsible for the care and issuance of all stores, has his office in the warehouse, and maintains a complete record covering receipt and issuance of all materials and of supply inventories (see page 618). Only the storekeeper and his assistants should be permitted to have access to the stores, individuals applying for materials on requisitions receiving them across a counter in the usual way.

There must ordinarily be a division of stores, some material being too heavy or too bulky to place in the same building with other materials, while others must be stored separately because of danger or fire risk. Casing, for example, is usually stored on out-of-door casing racks; timber and lumber in a timber yard; coal and coke, if necessary on the property, may be stored in stock piles; bar iron, rails, small pipe, boiler tubes, etc., are conveniently stored in long, substantially built racks. Fluid supplies purchased in large volumes, such as lubricating oils and gasoline, should be kept in a fireproof oil house. Metal storage tanks, equipped with suitable drains and valve controls, should be provided for lubricants since the wooden barrels in which they are shipped are often leaky occasioning heavy seepage losses and increasing the fire risk. Explosives must be stored in a fireproof magazine, well away from other buildings.

Small stocks of frequently used materials may, as a matter of convenience, be kept on various parts of the property outside of the warehouse. For example, a small stock of bolts, nuts, washers, rivets, nails, waste, packing, etc., will be maintained in the machine shop for current use. Small quantities of lubricating oil must be in reserve at the various wells, in the power house, shops, the garage or wherever machinery is operated. Stock supplies of this character may be drawn in quantities sufficient for a week's needs by the several departments, thus relieving the store-keeping records of a host of small requisitions. In the case of a group of scattered properties, it will be advisable to maintain well-equipped branch store houses at each property.

The Tool Rack.—Tools, like routine supplies, represent money, and should be given the same care and attention as is customarily given to merchandise in the warehouse. The variety of tools used on an oil-producing property is large, and a suitable place of storage should be provided. Usually a tool rack will be built for this purpose, as an adjunct to the warehouse, and the tools will be placed under the care of the storekeeper who charges them out and in as they are taken from or returned to the rack. A record should be kept of the location of each tool when it is not on the rack, so that if it should be urgently needed, the individual in charge of the tools would know exactly where to find it. The tools stored are, for the most part, drilling and fishing tools, heavy and cumbersome, and for convenience the rack should preferably be on a platform built at the same level as the bed of a motor truck, with a roof overhead, but without walls. Timber supports make it possible to stand the tools on end for convenience in handling and inspection. Because of the great weight of many of these tools, a chain hoist suspended from a swinging crane or from a small traveling crane is of great assistance in handling them from the rack to the motor truck or other conveyance used.

Water Supply.—An adequate supply of water is absolutely essential in the development and operation of an oil-producing property. Aside from the necessity of a source of pure water for drinking and general camp purposes, it is necessary in the generation of steam power, in cooling gas engines and other types of internal combustion engines, in fire protection and in cooling towers used in connection with natural-gas gasoline extraction plants. Water is also necessary in the drilling and cementing of wells, particularly in rotary drilling, where the circulation of a large quantity of liquid must be maintained.

If a sufficient supply of water cannot be impounded in reservoirs or secured from surface streams, it is usually possible to utilize ground water pumped from wells drilled for the purpose. The drilling of water wells and pumping of water therefrom may prove expensive, however, and the water is often brackish or even highly saline, requiring chemical treatment before it is suitable for use (see page 434). In some oil fields, local water companies, operating as public utilities,do a lucrative business.

In addition to developing a supply of water, the oil operator is confronted with the necessity of accomplishing its distribution. This requires a carefully constructed system of piping leading from a reservoir or elevated tank to give the necessary pressure, to the various points of use. Often the water must be initially pumped to this elevated position.

Electric Lighting.—Incandescent lamps provide the most satisfactory means of lighting, and current for this purpose is readily developed by and distributed from a generator placed in the power house. Aside from the superiority of the ordinary incandescent lamp in providing illumina-

tion for grounds and buildings, considerations of safety require its use in the vicinity of oil and gas wells, storage tanks, gas compression plants, or wherever inflammable vapor may be present. A lamp placed on the end of the beam at each pumping well serves to advise a distant observer of any interruption in pumping service during the hours of darkness, a considerable aid to the "pumper" in operating a group of scattered wells.

Transmission of current for lighting purposes may best be accomplished with an ordinary balanced three-wire circuit, using 110-volt current to avoid the necessity for transformers. A two-wire system will be suitable if the distance of transmission is not too great.

At wildcat wells remote from camp facilities and transmission lines, it is often economical to install a small steam-driven turbo-generator at the boiler plant which serves the well. Generators of this type will deliver 1 or 1½ kw., and can be installed and operated at small cost. Considered as a protection against fire, its initial cost becomes negligible.

Fire protection has been discussed to some extent in its relation to high-pressure oil and gas wells in Chap. X, and the prevention and control of oil tank fires has been discussed in Chap. XVIII, but other aspects of the subject should be mentioned at this time in connection with the protection of buildings and general camp facilities. A liberal supply of hand fire extinguishers of approved type, well distributed throughout the plant, is economy. Though buildings may be and usually are insured, there can be no insurance against the delay and inconvenience that results through the loss of an important plant unit, and the knowledge that the plant is insured should not prevent the exercise of due vigilance and preparedness toward fire protection. In addition to the well-known soda-acid, carbonic-acid hand extinguishers, which operate automatically when inverted, carbon tetrachloride (pyrene) and "foamite" froth-forming solutions (see page 543) are now widely used. Pyrene guns are especially useful in offices, laboratories, power houses and shops in controlling small fires in the incipient stages. Foamite solutions applied from hand pails, the two solutions being kept in separate compartments of the bucket, uniting when thrown, are useful in extinguishing small fires extending over floors and surfaces of small open tanks.

A large water main with fire hydrants located at strategic points should traverse the camp, particularly in the vicinity of the more important buildings and plant units. Fire hose of large diameter, conveniently coiled or reeled for ready use, should be placed in weather-proof boxes near the water connections, or a hose cart kept at some central station may be equipped with a long line of hose for transporting water to buildings located at some distance from the water supply. If the water system is under low pressure, a high-pressure transfer pump may be placed in the power house and connected with the water main, to be

operated only in case of fire. A group of men trained in the use of the fire-fighting equipment and held accountable for service in time of fire, should be within call of the power house fire whistle.

Accommodations for Employees.—While not directly concerned with the development and operation of the property, the provision of boarding houses, bunk houses and dwellings is an absolute necessity if the property is remote from any town where living accommodations may be had. Considerations of labor efficiency and contentment among the employees require that this aspect of the oil company's activities be not slighted.

The boarding house is often operated by the company, with a manager or steward employed under salary, though many companies seek to avoid responsibility for culinary difficulties by leasing the facilities to outsiders. Board is provided for employees of the company at a stipulated monthly rate, which often enters as a consideration in the employees' wage or salary agreements. It is sometimes stipulated, if other privately owned boarding houses are operated in the vicinity, that all unmarried men shall board at the company's establishment.

Sleeping quarters for employees should be comfortably furnished, and accommodations should be ample to prevent overcrowding. Rooms should be well lighted and ventilated, and provision should be made for heating them during cold weather. In a warm climate, it is desirable to have wide verandas, double roof construction and other features, such as shower baths, tending toward warm weather comfort. Small or moderately large units of from 6 to 12 rooms each are preferable to a single bunk house, since the latter is apt to be noisy and the fire risk is greater. In many cases, bedding is not furnished in the bunk houses, the occupants being required to furnish their own equipment except for the fixtures, such as beds, chairs, mattresses, etc.

Often separate and more pretentious accommodations are provided for the administrative and technical staffs, with well-furnished rooms cared for by a salaried attendant. Perhaps a cook will also be employed and a staff dining service maintained, so that the company officials may live entirely apart from the general group of employees. Such an establishment, if equipped with surplus facilities, will serve for the entertainment of visiting company officials and guests.

Cottages of four or five rooms are customarily built by the company for the accommodation of married employees. These are generally rented unfurnished, and are grouped together on a section of the property somewhat apart from the industrial center of the camp, and from the general bunk houses provided for unmarried men. Double houses, designed for the accommodation of two families, can ordinarily be built at lower cost than individual cottages of equivalent capacity. More commodious and better equipped houses are usually provided for the members of the administrative staff and their families, and these too, are

located somewhat apart from the main group of buildings comprising the camp.

Some companies are able to realize a considerable profit on the rentals and board money paid by employees for such facilities, but in many cases they are maintained at cost, or even at a loss. It is undoubtedly a poor policy to give anything less than full value for money paid by employees for board, lodging and rentals, and some companies spend a portion of the money allotted for welfare work among the employees, in improving these services.

One of the first principles of industrial efficiency is that the workman must be reasonably contented with his surroundings. With the aim of making the camp surroundings more attractive, lawns, gardens and trees are planted, and one or more individuals may be employed in caring for them and in keeping the camp buildings and grounds orderly. A swimming pool, a baseball field and tennis courts will be popular features.

Camp sanitation* is an important consideration, one that often receives but scant attention until the community is visited by a costly epidemic. The company physician should be asked to advise on matters of sanitation and general health conditions within the community, and the management should make every effort to provide the best possible facilities for improving conditions in this respect. Sanitary toilets and an adequate system of sewage disposal should be provided. Garbage and general camp refuse should be systematically gathered and disposed of. Pools of stagnant water in the vicinity of the camp should be drained and mosquitoes and flies exterminated. The water supply should be occasionally inspected and tested. Individuals having contagious diseases should be promptly placed in the hospital and quarantined.

The Camp Store.—For the convenience of employees on oil properties remote from towns and sources of supply, it is often desirable to have within the camp, a store dealing in general merchandise. Such an establishment may also conveniently serve as the camp post-office, express office and telephone exchange. The company will in some cases operate the store under the direction of a salaried manager for ordinary commercial profits, but most companies prefer to lease the facilities to a reputable merchant. Operation by the company has the advantage that a plan of cooperative buying may be worked out, resulting in lower prices and greater satisfaction to the customers, and consequently indirect advantage to the company through less insistent demand for higher wages. Many companies prefer, however, to avoid the criticism that seems inseparable from company-operated institutions, by placing the store under independent management. Employees are usually given a limited credit at the store, the amounts due for merchandise

* Bowie, C. P., Oil camp sanitation, U. S. Bureau of Mines, *Tech. Paper* 261, 1921.

supplied to individuals during each month being deducted from their monthly pay checks.

Buildings for Oil Field Service.—The type of building to select for oil field purposes will depend upon the use to which it is to be put, the climate, the fire risk and the probable life of the field. Many oil fields are so short-lived that only inexpensive, semi-permanent structures are justified. For shop buildings, warehouses and power houses, a simple timber-frame structure, sheathed with corrugated galvanized iron, is well adapted. Such a building will be inexpensive, fireproof, and will have a life of from 10 to 20 yr. in most climates. Galvanized iron, however, gives poor protection against extremes of heat and cold, and is therefore not well adapted for office buildings, bunk houses or dwellings. For such purposes, buildings of wood or hollow tile, with double walls and floors, should be provided. Building space is not ordinarily a factor of importance in oil camp construction, hence buildings may be located well apart in order to secure the maximum of light and to reduce the fire risk.

CHAPTER XX

OFFICE METHODS AND RECORDS

The importance of an adequate system of reports, records and accounts as an aid in the management of an oil-producing property, is recognized by every engineer. A capable manager requires, first of all, an intimate knowledge of every detail of the operations under his control; but due to the complexity of the business of oil production, and the large scale upon which operations are usually conducted, it is often impossible for him to exercise direct personal control. Division of responsibility, with the creation of staff relationships, is a logical development of this condition; and with this comes the necessity for a well-coordinated system of administrative records and reports. The financial aspects of the oil company's business require also a complete accounting for all income and expense, in order that profits or losses may be accurately determined. Cost records must be devised and maintained to provide a basis for analyzing the work of various departments, and for distinguishing between the profitable and unprofitable elements of the business. For the same purpose, the production of the property as a whole, and of each individual productive unit, must be carefully recorded; and further, the disposition of the production must be known in detail in order that accounts due the company may not be overlooked. Supplies, labor and miscellaneous services are necessary in operating the property, and in regulating payments to the individuals and agencies furnishing these commodities and services, a careful record of their value must be preserved.

In the oil field office it is customary to prepare and maintain six different series of records which may be broadly classified as follows: (1) the accounting records; (2) the cost records; (3) records concerning the payment and distribution of labor; (4) records concerning the purchase and distribution of supplies and power; (5) production records; and (6) administrative reports.

Organization of Oil Companies.—The planning of a satisfactory system of records and reports requires that a definite understanding be reached concerning the responsibility and authority of all individuals in the organization, and of their relationship, one to another. When this has been satisfactorily determined it is well to record the resulting plan in an organization diagram. Fig. 330 presents a common form of organization for a large oil company.

The clerical work of the oil company staff is usually divided between two (or more) offices, one group of executives and clerical workers being located in the field, on or near the producing property, while the other constitutes the personnel of the "home" office, located in the city in which the company has established its headquarters—usually a city in

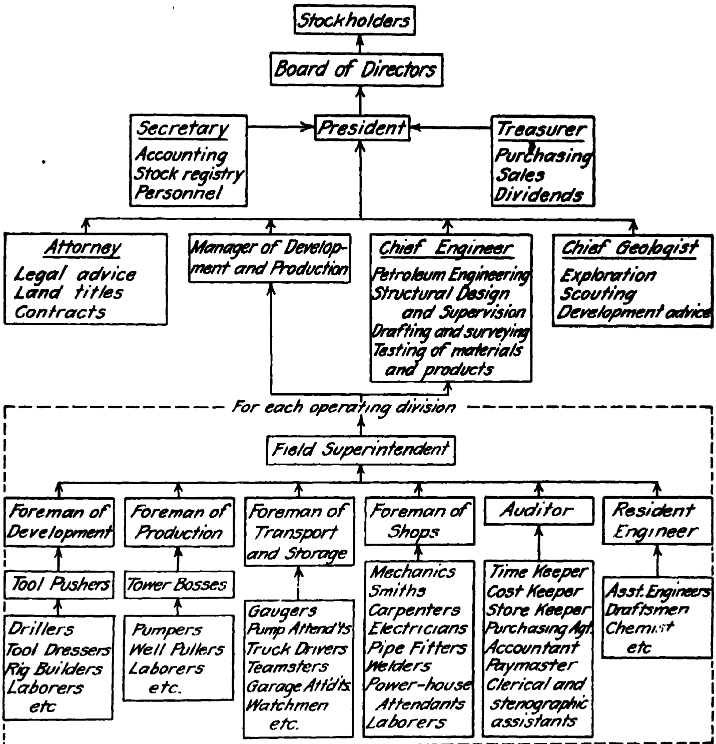
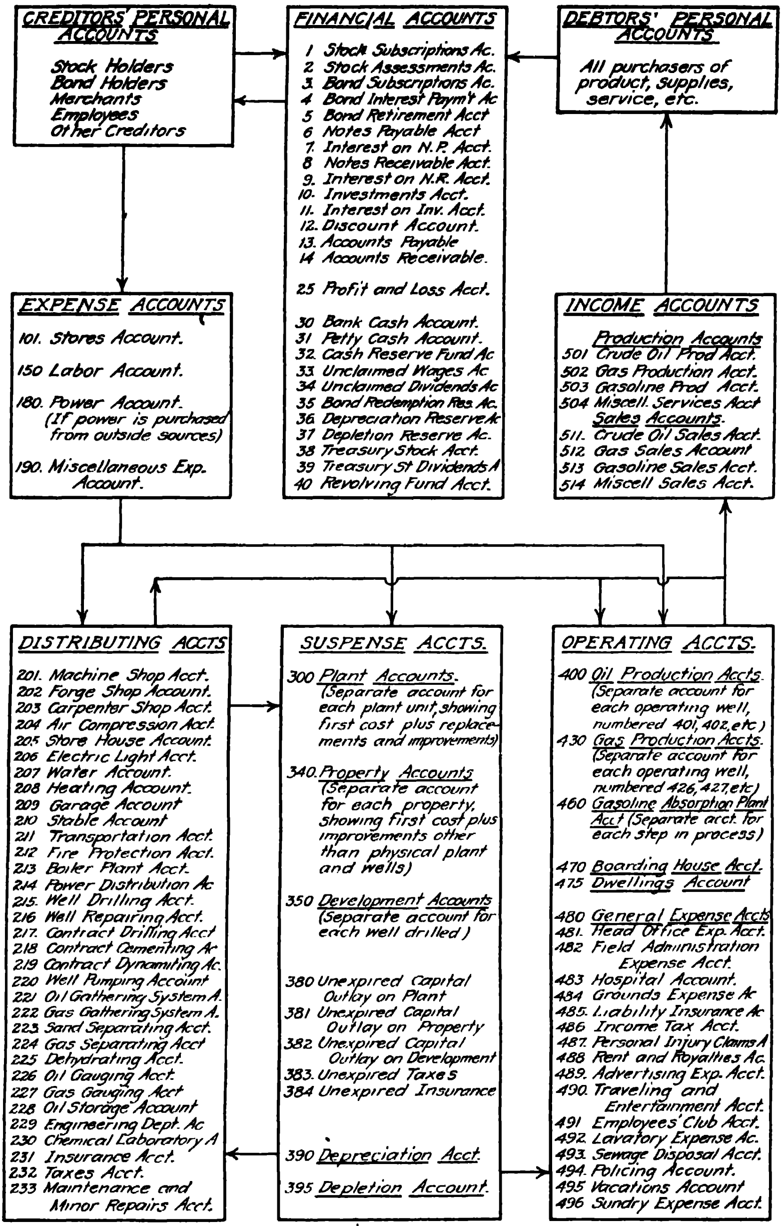


FIG. 330.—Organization diagram for a large oil producing company.

the state or country in which the company is incorporated. Between these two offices there is necessarily frequent communication. In many cases, the records and reports prepared in the field office are primarily for the advice of the head office officials.

A System of Accounts for an Oil-producing Company

In devising a system of accounts, it is important to have a sufficient number, so that the interests of every department or subdivision of the business are properly cared for, and so that no single account will have to serve more than one purpose. Since oil production is an intricate business, requiring many different activities, there must necessarily



(Accounts under-lined may be further subdivided).

FIG. 331.—Main ledger system of accounts for an oil producing company.

be a considerable number of different accounts. In Fig. 331 there is presented a diagram illustrating the relationship existing between the various accounts of a typical main ledger system for an oil-producing company. Every account represents a separate department or interest. The arrows show the normal course of entries to and from the different accounts. It is advisable to prescribe the course of all ledger entries rigidly, so that all similar transactions will be recorded in the same manner, and will take the same course through the accounts. Such a diagram standardizes the accounting procedure and largely eliminates the personal factor in such matters.

In explanation of the system of accounts illustrated in Fig. 331, it should be noted that all items of income and expense are provided with an account for primary entry. A group of creditors' personal accounts take care of all credit entries, indicating the source of assets received, such as capital, labor, equipment, supplies and power. Appropriately named accounts provide places of entry for corresponding debit entries. A group of production and sales accounts provide a means of recording transfers of oil, gas and other assets to debtors' personal accounts. The company's various financial interests are represented in the system by a number of appropriately named capital accounts, and cash and securities accounts. As an aid in determining the cost of operating the several departments of the business, we must have a group of operating accounts. These yield production that is directly responsible for the company's revenue. Some departments are not in themselves productive of revenue, but are engaged in supplying services of various sorts to the directly productive departments. These are permitted to distribute their operating costs among the other departments to which they render service, and for this purpose we must have a group of "distributing" accounts. To provide a means of holding in abeyance certain capital expenditures for assets productive of revenue over a long period of time, and distributing their value over the period of their use, accounting principles require that we establish a group of suspense accounts. These include chiefly the plant, property and development accounts, which are permitted to make periodical transfers of charges against the operating and distributing accounts to cover depreciation of plant and depletion of property.

The financial accounts comprise several groups. The capital accounts are concerned with stock subscriptions, assessments, dividends and other related matters involved in securing and refunding capital. The cash and securities group of accounts includes a variety of fund accounts provided for various purposes and others for recording interest returns and other sources of pecuniary income. As a means of determining changes in net worth, a profit and loss account is provided, under which expenditure is periodically balanced against income. The accounts receivable

and accounts payable accounts are not essential, but are useful in bringing to a focus a large number of related transactions so that their aggregate influence on profit and loss may be readily summarized.

The expense accounts are accounts of primary entry for stores, labor, power and miscellaneous expense, and provide a means of determining total primary expenditure before spreading over the operating, distributing, plant and development accounts.

The distributing accounts include all accounts representing departments which provide services of various sorts for other departments. They are not permitted to carry debit balances forward from one period to another, and hence must distribute their operating expense periodically over the departments receiving the services which they provide. The basis for distribution will vary, depending upon the nature of the services rendered. In some cases, as in the shop accounts, distribution may be made according to computations showing the actual cost of the work done; in certain of the distributing accounts, distribution of expense will be based upon the number of units of service supplied, as in the electric lighting accounts; in others, distribution will be according to the quantity of oil handled or produced, as in the oil dehydrating account; and in some cases, as in trucking, time spent will be found an equitable basis for distributing the expense.

The Suspense Accounts and Related Accounts.—Capital expended in purchasing and developing oil property, and in equipping it for operation, is productive of revenue over a relatively long period of time, usually throughout the productive life of the property. Such expenditures often involve large sums, and it would be obviously unfair to charge them against the operating costs of the particular period in which they were incurred. A more equitable plan is that of holding them in suspense and prorating them on some suitable basis against the operating costs of the entire period over which they are of service. Expense incurred in the purchase and development of property and the provision of plant is charged against either the property account, the development account or the plant account, as the case may be, and when the total cost of the development work or plant unit is determined, it is carried into a similarly named "unexpired capital outlay" account. Here it is held in reserve over the period of use, periodical charges being made on some suitable basis against the operating and distributing accounts through the depreciation and depletion accounts. Expense representing plant which is of service for a comparatively short period of time, say for less than one year, should be excluded from the suspense group and charged directly against the operating or distributing accounts as maintenance expense. Consideration of the nature of depreciation of oil field plant and depletion of oil property leads to the conclusion that the former should be charged off on a time (straight-line) basis, while the latter, as well as the cost of

development, should be written off in annual sums proportional to the quantity of oil produced; that is, according to the theoretical production decline curve of the property. While the sums to be charged against revenue as depletion and depreciation are revised annually, the annual contributions so determined are actually applied in monthly instalments, so that each cost period bears its proportionate share of the burden.

The operating accounts are those which are immediately productive of revenue. If full detail is required, we must have a separate operating account for each well, and against this will be charged the cost of power, labor, materials, maintenance and minor repairs, depreciation, depletion and miscellaneous distributed expense incurred in operating that particular well. The primary purpose of this procedure is to ascertain the cost of operating each well, a figure which may be contrasted with the value of its production to determine whether or not the operation of the well is profitable, and to what degree. In addition, we must have as a member of the group of operating accounts, a general expense account, to take care of items of operating expense of so general a character that they cannot be allocated directly against any particular well or department. If the company is operating a natural-gas gasoline extraction plant or a topping plant on the property, there must also be additional operating accounts covering these profit-earning activities.

The income accounts include a group of production and sales accounts which record the income derived from the product of the property. Thus, we will have an oil production account, a gas production account, an oil sales account and a gas sales account. The production accounts must be distinguished from the sales accounts in order to provide a means of accounting for product on hand awaiting sale. Oil and gas will be debited under the appropriate production accounts at cost value as soon as produced, and when sold, the production accounts will be credited and the value carried through the sales accounts and debited against the purchaser's account. The unbalanced increment or decrement between cost of production and selling price will eventually appear under the profit and loss account when expense is balanced against income.

The Books of Account.—In addition to the conventional ledger, journal, day book and cash book, a variety of other books and forms are desirable in facilitating the work of the oil company accountant.

Miscellaneous side ledgers are useful in relieving the main ledger of a host of minor accounts. For example, we may have a Sundry Creditors' Ledger, and a Sundry Debtors' Ledger, in which the accounts of companies, firms and individuals with whom we have dealings may be kept. In addition, books of ledger form are usually provided to serve as a Stock Subscription Register and Dividend Register. Other side ledgers may be used for the relatively inactive plant, property and development accounts; and still another may be employed in recording the details

of plant depreciation and property depletion. If full detail is desired in accounting for the cost of operating each well and each department, it will be found convenient to maintain an operating accounts ledger and a distributing accounts ledger. By arranging that each one of these side ledgers shall be represented in the main ledger by summarizing accounts, the permanent record provided by the main ledger may be much simplified.

6" Oil Line Dehydrating Plant to Tank Farm. 1917 to 19--

(Oil Gathering System Account).

Changes in estimates, date:	1919	1922	--------
Estimated Life: 10-years. Altered to:	10	8	--------
Estimated Scrap Value: $150. Altered to:	200.	150.	--------

Year	Original capital outlay		Less scrap value		Additions, Betterments, Renewals.		Total service value		Annual depreciation provision		Balance still to be depreciated	
1917	1650	00	150	00	----	--	1500	00	150	00	1350	00
1918	----	--	----	--	----	--	----	--	150	00	1200	00
1919	2200	00	200	00	550	00	2000	00	200	00	1800	00
1920	----	--	----	--	----	--	----	--	200	00	1600	00
1921	----	--	----	--	125	00	2125	00	212	50	1387	50
1922	----	--	150	00	----	--	2075	00	259	50	1128	00

FIG. 332.—Typical form for plant depreciation record.

The cash book should be supplemented by a Check Register in which a serial record of all checks issued is kept, while a voucher record book provides a similar means of keeping systematic account of vouchers issued in connection with the company's internal business affairs. Separate accounts payable and accounts receivable books are useful in regulating the payment of bills and collection of revenue.

The primary record of expenditures for labor and supplies may conveniently be a periodical form report. Thus, it may be arranged to have the time keeper or paymaster submit a monthly Payroll Summary, while the storekeeper presents a monthly report of Stores Received and Issued. Such reports serve as a substitute for a group of accounts arranged in ledger form, and their total figures may be the basis for debit and credit entries made monthly in the main ledger.

In recording depreciation of plant, a Register of Plant must be provided, in which is entered the first cost of each plant unit, together with subsequent extensive repairs, replacements and renewals, so that the total investment may be determined (see Fig. 332). Estimates are

made of the useful life of each plant unit and of the depreciation rate in order that appropriate annual reductions in remaining service value may be computed. Annual surveys of the plant should be conducted to determine the condition of each plant unit, and if original life estimates are found to be in error, they may be revised from year to year. The primary purpose of such a record is to spread the cost of plant in the cost

TABLE XLVI.—AVERAGE USEFUL LIFE PERIODS AND DEPRECIATION RATES FOR OIL FIELD PLANT*

Equipment	Average useful life, yr.	Annual deprec rate, per cent
Drilling equipment	4	40–25 15–10
Dehydrators:		
Electric	5	20
Pipe and tanks	2	50
Tanks:		
Steel, 5,000–55,000 bbl	20	5
Steel, 2,500–5,000 bbl	12	$8\frac{1}{3}$
Galv iron, 500–2,500 bbl	12	$8\frac{1}{3}$
Less than 500	8	$12\frac{1}{2}$
Wood	5	20
For movable tanks:		
Galv. iron, 500–2,500 bbl	9	$11\frac{1}{9}$
Less than 500	6	$16\frac{2}{3}$
For water tanks:		
500–2,500 bbl	8	$12\frac{1}{2}$
Less than 500 bbl	5	20
Tools	3	$33\frac{1}{3}$
Transportation equipment	3	$33\frac{1}{3}$
Water plants	10	10
Electric equipment	10	10
Machine shops	7	$14\frac{2}{7}$
Buildings:		
Small wood	10	10
Frame structure	15	$6\frac{2}{3}$
Corrugated iron siding	6	$16\frac{2}{3}$
Concrete	25	4
Brick	25	4
Steel	25	4
Pipe lines:		
Mains over 6 in in diam	20	$4\frac{1}{2}$
Mains under 6 in in diam.	16	$5\frac{5}{8}$
Gathering lines (less 10% salvage)	10	10
Pump stations	10	10
Tank cars	20	5
Natural-gas gasoline plants:		
Compression plant with 20% salvage value	6–10	$16\frac{2}{3}$ 10
Absorption plant with 20% salvage value	6–10	$16\frac{2}{3}$ 10

Equipment	Average useful life, yr.	Annual deprec rate, per cent
Refineries:		
Class 1 Located at point assuring long supply of crude; well-constructed plants	20	5
Class 2 Located at points assuring supply of crude for several years	10	10
Class 3 Skimming plants and small refineries of poor construction, or located at points where supply of crude is not assured for long period of time	6	$16\frac{2}{3}$
Marketing equipment:		
Tankers	20	5
Barges	5	20
Filling stations:		
Wood or corrugated iron	5	20
Brick and concrete	10	10
Distributing stations	10	10
Tank wagons;		
Motor	4	25
Horse	6	$16\frac{2}{3}$
Steel barrels	7	$14\frac{2}{7}$
Track and switches	8	$12\frac{1}{2}$
Natural gas equipment:		
Gas pipe lines:		
Mains	12	$8\frac{1}{3}$
Gathering lines	10	10
City lines	10	10
Compressor stations	7	$14\frac{2}{7}$
Gathering stations	6	$16\frac{2}{3}$
Field stations	4	25
Meters and regulators	5	20
Plant, considered as a single unit	10	20

* After U. S. Internal Revenue Bureau's "Manual for the Oil and Gas Industry under the Revenue Act of 1918" (with corrections).

accounting records, over the period of its use, as uniformly as possible. It is also useful, however, in determining insurance premiums and in making income tax returns. Suitable depreciation rates for various classes of oil field plant are given in Table XLVI, though it should be pointed out that such rates vary within wide limits, and that whatever rate may be initially adopted, it should be occasionally checked and perhaps altered from time to time to conform with actual apparent decrease in service value of the plant units. In the case of some long-lived classes of plant, the useful life will be contingent upon the productive life of the property.

Lockhart Lease, S.E.¼ of Sec. 16, T. 32 S., R. 14 E., M.D.M. 1913 to 19__

Title: Leased on one-eighth royalty with bonus of $75,000. (Depletion Account)

Changes in estimates, dates: ________

Estimate of ultimate yield: 4,800,000 bbl

Estimated residual value: $15,000. Altered to: ________

Year	Original capital outlay		Less residual value		Additional capital outlay (Development)		Total value of wasting assets		Depletion charge per barrel oil		Annual production barrels	Annual depletion provision		Balance still to be written off	
1913	75,000	00	15,000	00			60,000	00						60,000	00
1914					388,916	16	448,916	16	0	0935	764,016	71,435	49	377,480	67
1915					402,824	86	780,305	53	0	1933	1,257,037	242,985	25	537,320	28
1916										"	839,993	162,370	65	374,949	63
1917										"	563,053	108,838	14	266,111	49
1918										"	484,164	93,588	90	172,522	59

FIG. 333.—Typical form for property and development depletion record.

Depletion of property may be recorded in a Property Register, suitably arranged to display the total original cost of the land, plus the cost of drilling the wells and all permanent well equipment (see Fig. 333). The ultimate production of the property is determined as soon as the decline curves can be worked out, and the depletion charge per barrel of oil is computed by dividing the total cost by the total production. This unit charge is later applied against each barrel of oil produced. The property register records the annual depreciation charges and the value of the remaining oil reserves. Natural gas production must also be included if it has commercial value. The depletion rate may be altered from time to time as changes in the apparent oil reserves may warrant.

The Cost Records

The cost records are closely related to the expense, suspense, distributing and operating accounts outlined above, and represent in one sense a detailed analysis of them. They are made up of carefully selected items of expense combined and arranged in such a way as to display in convenient units for comparison, the cost of each step in the process of oil and gas production, as well as the detailed cost of operating each department. Cost data are prepared primarily for the use of administrative officers, engineers and others who are charged with responsibility for the efficiency with which the work is conducted, and who are required to estimate the cost of new work.

The elements of production cost are three in number: (1) direct labor, or labor that is directly employed in production of output; (2) direct material; and (3) indirect expense, which is made up of certain labor and material charges that cannot be directly allocated against output, and miscellaneous other expense that does not partake of the nature of either labor or material. All cost records may be reduced to these elements, but ordinarily it is necessary to give further detail than is afforded by so broad a classification. Accordingly, in developing a cost record, we expand the three primary cost elements into a group sufficient in number to display fully the regularly recurring, major items of expense.

Cost records may be conveniently kept on either loose-leaf printed forms, or on cards arranged in card catalog form in a vertical filing cabinet. The latter method is generally preferred for the primary records kept by the cost keeper, but cost sheets prepared from the originals for the use of executives and others are usually reproduced on loose-leaf printed forms. A 5-in. by 8-in. card is suitable for the use of the cost keeper. These cards may be had in a variety of colors, and may be printed or multigraphed to order with any desired arrangement of columns and headings. A suitable filing cabinet, or desk equipped for card filing, is essential.

In designing the cost records, the needs of each department must be carefully studied to devise a suitable form for the record, to select the important items of expense and to determine the most convenient units in which to express the results. Each record will necessarily differ from every other, but a certain measure of uniformity in size and arrangement of data is desirable. The forms reproduced in Fig. 334 are typical.

The cost keeper must depend upon individual and group reports from workmen or foremen in direct contact with the work for the primary distribution of labor expense. This information is made available by requiring individuals or foremen to prepare daily reports indicating the work accomplished during each hour or each "tour" (shift). The driller

Cost of Drilling Well No. 16								May 15, 1923 to Sept. 25, 1923
Month:	May	June	July	Aug.	Sept.		Cost Total	Per Foot
Feet Drilled								
Drillers								
Helpers								
Power								
Maintenance and Minor Repairs								
Miscellaneous Supplies								
Depreciation of Drilling Equipm'nt								
Tool Sharpening								
Transportation								
Electric Light								
Water Supply								
Miscellaneous other Expense								
Total Cost								

Total Cost of Well No. 16.								
Month	May	June	July	Aug.	Sept.		Cost Total	Per Foot
Equipment								
Derrick								
Permanent Rig								
Engine (or motor)								
Casing								
Cement								
Tubing								
Sucker Rods								
Pump								
Development Cost								
Well Drilling								
Contract Drilling								
Contract Cementing								
Contract Dynamiting								
Roads								
Engineering								
Administration								
Re-drilling and Extensive Reps.								
Total Cost								

Cost of Producing Oil and Gas Well No. 12								January, 1923 to June, 1923
	Average previous 6-months	Jan	Feb.	March	April	May	June	6-months Average
Pumping								
Maintenance & Minor Repairs								
Gas Separating								
Sand Separating								
Oil Gathering								
Gas Gathering								
Oil Storage								
Electric Lighting								
Taxes								
Insurance								
Fire Protection								
Depreciation								
Depletion								
Royalty								
Miscellaneous expense								
Total Cost per Month								
Cost per Day								

FIG. 334.—Typical cost record forms.
(The second form is conveniently kept on the reverse side of the card containing the first record).

in charge of a drilling well, for example, will submit a "tour" report with the names of the various members of his crew, the footage drilled, or other work accomplished, the materials used, etc. If several wells are in process of drilling at one time, the "tool pusher" or foreman in charge of drilling may be required to prepare a group report indicating the number of men employed, and the work to which they have been assigned for each tour. Work in process in the shops will be handled on an hourly basis, requiring the individual workmen to fill out reports at the end of each day, specifying the work accomplished and the time spent on each job. The various jobs routed through the shops are given serial numbers for convenience in reference. Rig building, pipe line construction, grading, road building and other structural work, will require special consideration in devising a series of reports that will give the cost keeper such information as he may need to assemble the cost data in the most convenient form.

The storekeeper will be in a position to furnish complete information on the cost of materials used in different phases of the work, from the requisitions presented when the material is drawn from the warehouse; though in some instances, further particulars will be needed from the foremen in charge of the work.

Distribution of power expense is often difficult. Methods of attack will vary with the kind of power used and the purpose for which it is used. If steam power is employed, and several plant units are supplied with steam from a central boiler plant, meters placed in the transmission mains to each point of consumption will provide records of steam consumption, on the basis of which the cost of operating the boiler plant may be distributed. If electric power is used, wattmeters provide a ready means of recording the service given. If individual gas engines are used in pumping the wells, we may distribute the total cost of the gas among the several wells by taking occasional meter readings of gas consumed by each engine. We may approach the problem from another direction by studying the actual performance of the engine or motor used. In many cases an accurate distribution of power expense will be impossible, and the cost keeper must depend upon arbitrary assumptions of the percentage of total power consumed in each department.

Similar difficulty is experienced in distributing certain kinds of overhead expense. In the shops, for example, there is a considerable element of general expense, including such items as salaries of foremen and general helpers, small routine shop supplies, power used in driving shop machinery, maintenance and upkeep of shop equipment. Such items may reach a high percentage of the total cost of operating the shops, and must be distributed among the various jobs routed through the shop on some equitable basis. Distribution according to the number of direct labor-hours spent on each job is a convenient method.

In certain kinds of work, it is convenient to base charges for work done on time exclusively. For example, in trucking equipment and supplies about over the property, the average hourly cost of operating the truck, including the salary of the driver, gasoline, oil, depreciation and all other charges, may be computed, and each job or each department receiving service is charged with a flat rate per hour for the time that it uses the truck. Distribution of trucking expense may be more properly handled on a ton-mile basis where long hauls are involved, though the weight of materials transported is not always known.

Monthly Cost Summary							September, 1923.
Account	Barrels of Oil	Total Cost		Cost per Barrel		Cost per Day	
		This month	Average, last 6 mos.	This month	Average last 6 mos.	This month	Average last 6 mos.
Oil Production Accts.:							
Well No 1							
Well No 2							
Well No 3							
General Expense Accts:							
Field Office Expense							
San Francisco Office Exp.							
Hospital Expense							
Distributing Accts:							
Machine Shop Expense							
Forge Shop Expense							
Power Dist. Expense							
Total Cost							

FIG. 335.—Typical form for monthly cost summary.

Summaries of the cost records prepared for distribution among officials of the company should be condensed from the primary records kept by the cost keeper at regular intervals, usually monthly. Such records are intended to provide a means of comparing the efficiency of operation as between different periods. Care should be taken, in presenting the data, to select units that are suitable for comparative purposes. For example, in reporting the unit cost of oil production, the cost per barrel means little because the production of the wells is variable and bears little relation to the efficiency of operation. The cost per well per day or per month, however, is a unit that does not display such variation, and is directly dependent upon the efficiency with which the plant is operated. Fig. 335 illustrates a suitable form for the monthly cost sheets.

Graphic cost records may be used to advantage in supplementing tabulated cost figures. Graphic records are more easily interpreted and variations between different cost periods may be contrasted to much

better advantage than in the case of ordinary tabulated records. In a chart, one can see the abnormal results at a glance and center the analysis upon these, ignoring the normal figures which do not require administrative attention. Typical examples illustrating the use of

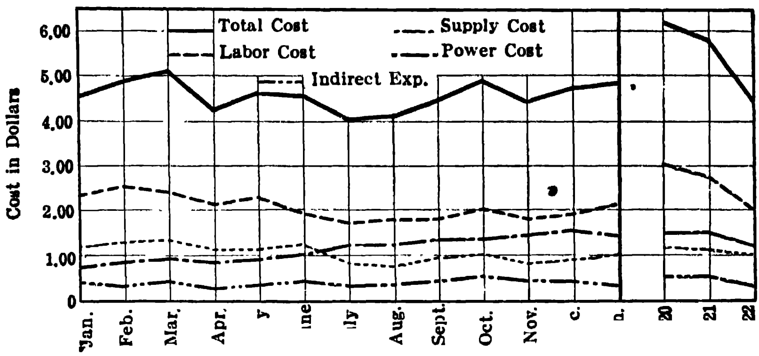


FIG. 336.—Graphic cost record showing average cost per well per day of operating a group of pumping wells.

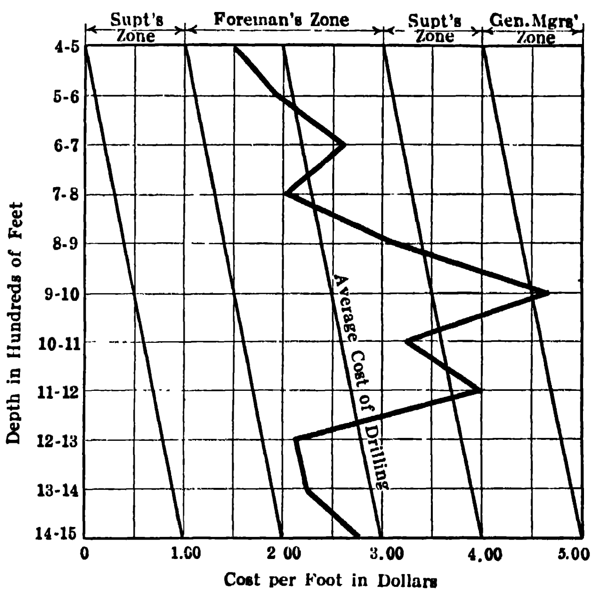


FIG. 337.—Type of graphic cost record suitable for displaying variations in the cost of drilling.

The heavy line indicates the actual cost of drilling a particular well, while the "average cost of drilling" line shows the average cost for the locality in which the drilling well is located.

graphic methods in displaying cost data are to be found in Figs. 336 and 337. In Fig. 337, costs are plotted with respect to an assumed normal, showing at once the extent to which actual costs vary from the theoretical normal. Such a record may be divided off into zones indicating the

responsibility for investigating the abnormalities of cost. Thus, the general manager would concern himself with the reasons for an abnormal result only when the cost curve extends beyond the superintendent's "zone," and the latter official would be obliged to investigate only when the graph passed beyond the limits of the foreman's "zone."

PAYMENT OF LABOR AND DISTRIBUTION OF LABOR EXPENSE

Labor represents the most important item of expense in oil production, and accounting for labor and distributing its cost among the cost records is one of the most important aspects of the cost keeper's work. Furthermore, as an employer of labor, the oil company is obligated, both in its own interest and for the protection of its employees, to maintain a careful record of the service furnished by each employee in order that the wages due him can be accurately determined.

Time Book Page 894 — *Month of September, 1923*

No.	Name	Occupation	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	Total No. Days	Rate per Day	Amount Due
10,602	A. Service	Driller	/	/	/	/	/	/	/	/	/	/	x	x	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/		28	8.00	224.00
603	F. Henderson	"	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/		30	"	240.00
604	J. Titus	"	/	x	/	/	/	/	/	/	/	x	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/		28	"	224.00
605	T. Mc Manus	"	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/	/		30	"	240.00
		Totals																																		928.00

FIG. 338.—Typical form for time record.

The remuneration of labor may be based upon the time worked, upon the amount of work done or upon the value of the oil and gas produced. Though illogical and contrary to the principles of efficiency and economy, the day-labor system, or payment according to the length of time worked, is the most commonly used method. Payment based upon quantity of work accomplished is occasionally met with in various piece rate, bonus and contract systems. Direct payment according to the value of the product is uncommon in the oil industry, though examples are to be found in the so-called profit-sharing plans adopted by the larger oil companies, in which employees are given an annual bonus based upon the company's yearly profit, or they are encouraged to buy the company's stock or bonds at reduced rates.

The Time Records.—It is customary to maintain a list of the employees' names, on which the hours or shifts worked by each individual are checked off daily (see Fig. 338). Such a record is generally placed in charge of a "time keeper," though in many cases the primary records

will be prepared by the foremen of departments. The individual workmen may be simply checked off on the time list as the time keeper or foreman makes his rounds of the property and plant and observes them at work, or more elaborate systems involving the use of time boards, checks and tickets may be employed. If all of the employees pass a certain point in going to and coming from work, they may be given individual numbered brass checks which they are required to hang on a

Daily Labor Segregation Report September 28, 1923.
Well Drilling and Operation Direct Labor Charges

Occupations	Wage Rate		No. Employed	Total Amt Due		Well No.	Distributed Charge		Hours: Pumping	Idle	Pulling or Cleaning	Engine Reps.	Re-drilling	Drilling
Tool Pushers	10	00	3	30	00	1.	2	28	24					
Drillers	8	75	9	78	75	2	2	28	24					
Derrick Men	6	75	9	60	75	3.	2	28	24					
Drillers' Helpers	5	25	27.	141	75	4	18	72	16		8			
Head Rig Builders	8	75	1.	8	75	5	2	28	24					
Rig Builders	7	75	2	15	50	6	7	64	20			4		
Rig Builders' Helpers	6	75	2	13	50	7	2	28	24					
Well Pullers' Gang Boss	6	75	2	13	50	8	2	28	24					
Well Pullers & Cleaners	5	25	4	21	00	9	2	09	22	2				
Engineers	5	50	6	33	00	10	4	77	20	2		2		
Firemen	5	00	6	30	00	11	2	28	24					
Boiler Washers	5	25	1	5	25	12	4	77	20	2		2		
Engine Repair Men	6	25	1	6	25	13	2	18	23	1				
Engine Rep. Helpers	5	25	1.	5	25	14	2	28	24					
Pumpers	5	00	9	45	00	15.	2	28	24					
Oilers	5	00	3	15	00	16	18	34	12	4	8			
Roustabout Gang Boss	6	00	2	12	00	17	2	28	24					
Roustabouts	5	00	8	40	00	18			0	24				
Tool Sharpeners	6	75	2	13	50	19	2	09	22	2				
						62	108	25						24
						63	108	25						24
						64	108	25						24
						65	89	75	Rigging up, Laying steam and water lines.					
Totals			98	588	75		588	75	1350	90.	16	8	—	72

FIG. 339.—Typical labor segregation record.

Other pages arranged in slightly different form, display segregation of labor charges for other departments.

board fitted with numerous similarly numbered hooks. Checks are placed on the board by the employees as they go to their work, and are removed as they come off shift. By inspection of the board, the time keeper readily posts the daily time book. Under still another plan, each workman is given a small book of tickets at the beginning of the month. The individual tickets in each book are numbered alike, and a list is kept of the book number of every workman. The workman gives one ticket to his foreman at the close of each day's work. The foreman indicates

on the ticket the work to which the employee has been assigned for the day, places all of the tickets for his crew in an envelope, which is sealed and sent to the time keeper. Such a method provides a primary record from which both the time records and the labor segregation records may be posted.

Periodically—usually once each month—the time keeper prepares a summary of the time record, indicating the total number of days or hours worked by each employee during the interval covered by the report, and the total amounts due. This is for the use of the paymaster in preparing

Pay Roll Page No. 164. Month of September, 1923.

Check No.	Name	Occupation	Days Worked	Daily Rate	Total Amt.	Deductions: Board	Deductions: Rent	Deductions: Others	Balance Due	Received Payment
10,603	F. Henderson	Driller	30	8.00	240.00	40.00	10.00	---	190.00	----------
604	J. Titus	"	28	"	224.00	---	20.00	---	204.00	----------
605	T. McManus	"	30	"	240.00	40.00	10.00	---	190.00	----------
606	R. Underwood	Tool Dresser	30	6.50	195.00	----	20.00	----	175.00	----------
607	M. Lee	"	29	"	188.50	40.00	10.00	---	138.50	----------
		Totals			7806.50	1040.00	540.00		6226.50	

FIG. 340.—Typical form for pay roll.

the payroll. The time keeper may also be required to prepare a "labor segregation record" (see Fig. 339), indicating the total number of hours worked by each class of labor, and the equivalent dollar value. This record may also show the distribution of labor by classes among the several departments and jobs in process. Such a record provides the basis for labor entries on the cost records, and is the basis for journal and ledger entries covering labor distribution over the various accounts concerned.

In preparation for "pay day," the paymaster enters on the payroll (see Fig. 340) the name and number of each employee, his classification and daily wage rate, and the amount due, as indicated by the time record summary. Certain deductions may then be made for board, lodgings, rentals, hospital and other fees, and the net amount to be paid each individual determined. Checks are then written, and when delivered to the employees, they are required to sign the payroll as evidence of payment. Ordinarily, two copies of the payroll are prepared, one for the field office record, and the other to be sent to the head office of the company as a voucher record of payments made. Payment of wages is sometimes made in cash, but this is undesirable if it can be avoided because of the likelihood of error in making payment, and the risk of robbery and theft.

PURCHASE AND DISTRIBUTION OF SUPPLIES

After labor, equipment and supplies constitute the largest single item of expense in oil production. The routine of purchasing, receiving and distributing supplies is therefore worthy of careful study. Responsibility for the placing of orders for supplies, for transportation from the market to the company's warehouse, and specifications covering quality and terms of purchase, are usually entrusted to a "purchasing agent." Care and distribution of supplies after they reach the property is delegated to the "storekeeper."

Two systems of buying are in common use: (1) buying on bids, and (2) buying on contract. The latter method is only suitable for use in purchasing commodities regularly used in considerable amounts. In the first of these two methods, the purchasing agent sends requests for prices, or "bids," to several merchants or supply dealers, specifying in detail the material he wishes to buy. When the bids are received and compared, the order is placed with the lowest bidder, or, in general, with the firm most acceptable to the buyer. This method of buying is preferred by most purchasing agents, but requires time for the necessary correspondence. In placing a purchasing contract under the second method, the buyer agrees to purchase, from the concern with which the contract is placed, all of the material of a certain kind that may be needed over a specified time, often a year or more. Certain minimum quantities which the buyer agrees to purchase within the period are often designated. As an inducement for such a contract, the merchant is usually justified in offering a price somewhat below the prevailing market price. Often, too, it may be possible to place a long-period contract at a favorable time in anticipation of a rise in commodity prices. In addition to the two methods of buying described above, when there is insufficient time for proper negotiations between buyer and seller, emergency buying is sometimes necessary. Emergency buying generally results in the buyer paying a higher price.

The purchasing agent undertakes the purchase of equipment and supplies on receipt of a "purchase requisition" signed by the storekeeper, a department superintendent or other authorized official of the company (see Fig. 341). Each purchase requisition is given a serial number which is placed on all subsequent correspondence and invoices relating thereto. Requests for bids are then sent out (see Fig. 342). After the bids are received and compared, the purchase order is sent to the successful bidder (see Fig. 343). The purchasing agent should maintain a file of catalogs descriptive of the materials and equipment in which he deals, and should keep posted on current prices so that he can prepare estimates of equipment and supply costs when requested to do so. He must be thoroughly familiar with the character and quantity of supplies

used by his company, and is often empowered to anticipate future needs in the placing of long-term contracts at favorable rates. He must exercise good judgment in these matters, and by his business acumen should command the respect of the concerns and individuals with whom he has to deal.

Purchase Requisition Nº 789

Petrolia, Cal., Sept. 16, 1923.

Purchasing Agent, Midvale Oil Co.,
San Francisco, Cal.,

Dear Sir:-

Please order the following supplies:

Date Wanted		Quantity	Description	Needed for	Bids Asked		Ordered	
					Date	Price Req Nº	Date	Purchase Order Nº
Oct.	1	1 case	Mazda Lamps, 40-watt	Elect. Lt. Acct.	9-18-23	2864	9-22-23	976.
"	1	6	Axelson 3" oil well pump liners	Oil Product. Ac	"	2865	9-23-23	982
Nov	15	3,000 ft	10"-40# D.B x casing	Well No. 32	"	2866	10-6-23	1067
"	"	1,000 ft	2"-Standard pipe, galv.	Water Sup. Ac.	"	"	"	"

Approved: ____________ Field Superintendent

Signed: ____________ Store Keeper.

FIG. 341.—Typical form for purchase requisition.

Price Request Nº 2874.

Midvale Oil Co.
1042 Merchants Exchange Bldg.

San Francisco, Cal., Sept. 20, 1923.

The Pacific Apparatus and Supply Co.,
Los Angeles, Cal.,

Gentlemen:

Will you please quote us your current prices on the following articles:-

Date Wanted		Quantity	Description	List Price		Discount	Net Price	
Oct.	15	2-Doz.	Centrifuge Tubes, 100cc. cap., (No. 2894-C.)	48	00	10%	43	20
"	"	1-Doz	Thermo-hydrometers, 19-31°B, A.P.I. (No 3765-A)	42	00	10%	37	80
"	"	1	Rorrison Oil Thief (Nº 796-B)	25	00	15%	21	25
"	"	5-gals	Bisulpholine	2	75	Net	2	75

Please use this form for your reply.

Terms: 2% cash, 30-days
F.O.B. Los Angeles.

Very truly Yours,
____
Purchasing Agent.

FIG. 342.—Typical price request form.

In addition to the duty of buying, the purchasing agent is charged with the responsibility of checking all supply and equipment invoices, and certifying them for payment. As invoices are received, they are compared with the original bid or contract and with the purchase order, and the price per unit, extensions and terms of payment are carefully checked.

Usually a discount is offered for payment within a specified time. Often 2 per cent discount is offered if payment is made within 30 days, though sometimes the period is as short as 10 days, and occasionally it may be as long as 60 or 90 days. Even 2 per cent of the aggregate amount expended by the average oil company for supplies and equipment is a

Purchase Order *Midvale Oil Co.*
Nº 1082. *1042 Merchants' Exchange Bldg.*

San Francisco, Cal., Sept. 28, 1923.

The Pacific Apparatus and Supply Co.,
Los Angeles, Cal.

Gentlemen:-

You are hereby authorized to furnish the material listed below as quoted on our price request Nº 2874.

To be shipped on or before		Quantity	Description	Agreed net price	
Oct.	15	2-Doz.	Centrifuge Tubes, 100 cc. cap., (Nº 2894-C)	43	20
"	"	1-Doz.	Thermo-hydrometers, 19-31°B., A.P.I. (Nº 3765-A)	37	80
"	"	1	Rorrison Oil Thief (Nº 796-B)	21	25
"	"	5-gals.	Bisulpholine	2	75

Please acknowledge receipt of this order and send duplicate invoices.

Ship to: Midvale Oil Co., Taft, Cal.,
via Southern Pac. and Sunset R.R.
Place our order number on all invoices and packages.

Very truly Yours,
Midvale Oil Co.,
by ....
Purchasing Agent

FIG. 343.—Typical form for purchase order.

considerable sum, and every effort is made to hasten the checking and certifying of invoices in order that payment may be promptly made and the discount secured.

Invoices are usually submitted in duplicate, one copy being pasted in an Invoice Record Book kept by the purchasing agent, while the other is sent by the purchasing agent to the accountant who makes the necessary ledger entries and prepares a voucher which is sent to the treasurer of the company, authorizing payment. After the goods have been received and an independent count and inspection and report has been made by the storekepeer, the duplicate copy of the invoice may be sent by the accountant to the storekeeper for his advice in posting prices on the Stores Record Cards.

When the goods are received, the storekeeper sends a Materials Received Report (see Fig. 344) to the purchasing agent, certifying to the number of units received and the quality and general condition of the consignment. It is desirable that the storekeeper should not have a copy of the invoice or purchase order before him when this checking of the goods is in progress, then he is compelled to count and inspect the material in order to fill out the material received report. The stores

record cards (see Fig. 345), are posted as soon as the new consignment of material is received, though the price columns may not be filled in until later.

Materials Received Report No. 1561				Purchase Order No. 1082.
Name of Shipper: Pacific Apparatus and Supply Co.				Date Received: Oct. 12, 1923.

Quantity	Description	Invoice Cost	Transp. Charges	Total Cost	Cost per Unit
2-Doz.	Centrifuge Tubes, 100cc. cap., (No. 2894-C)	43.20	0.70	43.90	1.83
1-Doz.	Thermo-hydrometers, 19-31°B., A.P.I. (No. 3765-A)	37.80	0.35	38.15	3.18
1	Rorrison Oil Thief (No. 796-B)	21.25	0.60	21.85	21.85
5-gals.	Bisulpholine	2.75	1.60	4.35	0.87

Debit Account No.	Amount	Ledger Folio	Goods Received by:
			Store Keeper.

FIG. 344.—Typical form for materials received report.

Material can be drawn from the warehouse only on requisitions signed by authorized individuals (see Fig. 346). When supplies are issued, the "materials charged out" column of the stores record cards is posted. Balances struck whenever goods are received or charged out on the stores record cards provide a permanent inventory of both the value and quantity of the supplies on hand.

2" W.I. Elbows.							January 1, 1923 to					
Date	Mater'ls Rec'd. Rept. No.	Units Rec'd.	Invoice Cost	Transp. Cost	Store House Expense	Total Cost	Balance on Hand		Average cost per Unit	Charged Out		
							Units	Cost		Req. No.	Units	Value
2-1-23	---	---	---	---	Bro't.	Fwd.	5	0.59	0.118	---	---	---
2-16-23	237	24	2.88	0.42	0.13	3.01	29	3.01	0.124	----	----	----
2-30-23	----	----	----	----	----	----	21	2.02	0.124	842	8	0.99
Balance Carried Forward							-----	-----	-----			

FIG. 345.—Typical form for stores record card.

The storekeeper is held responsible for the maintenance of a sufficient reserve of supplies regularly maintained in stock in the warehouse. It is customary to determine a stock minimum for each article, below which the quantity on hand is never permitted to go. The minimum varies with the extent of demand for the article and with the time necessary for a new consignment to arrive after an order for it is placed. Small bin tickets may be hung on hooks beside the bins in which stock is stored in the warehouse. These are printed with columns in which entries may be made of materials placed in the bins or withdrawn therefrom, and of balances on hand. When, on supplying goods specified on a requisition, it is found that a minimum for the article has been reached, the stock

clerk removes the bin ticket and hangs an "on order" bin ticket of special color in its place. The storekeeper at once sends a purchase requisition to the purchasing agent for a new consignment.

Periodically the storekeeper is required to prepare a Summary of Stores Issued Report indicating the cost value of all supplies and equipment charged to each department during the interval covered by the

Stores Requisition No. 546 *April 16, 1923.*

Purpose: ______ *Account Debited:* ______

Quantity	*Description*	*Price*	✓
	Total Charge		

Delivered by:	*Received by:*	*Approved.*
		Department Foreman

FIG. 346.—Typical form for supply requisition.

report. This report is made up from the requisitions presented, and first goes to the accountant who makes the necessary ledger entries, and then to the cost keeper for his information in computing departmental costs.

In order that the storekeeper may be in a position to assign definite values to the materials withdrawn from the warehouse, he must maintain a suitable price record, indicating at any time the average cost per unit for each article carried in stock. This is continually changing as new consignments are received, depending upon variation in market prices. The current price for each article carried in stock may be shown either on the stock record card (as indicated in Fig. 345), or it may be kept in a special price book, in which the supply items are arranged alphabetically. The charges made to departments drawing supplies from the warehouse must not only include the invoice cost, but also the cost of transportation to the property, and a prorated charge covering the cost of operating the warehouse. This latter item includes such items as the salaries of the storekeeper and warehouse attendants, insurance on the warehouse and stock, and breakage losses and depreciation of stores.

In connection with store keeping and purchasing, quality tests on materials purchased are occasionally necessary to determine whether or not they conform with the purchase specifications. This work may be done in the laboratory, or it may be conducted by actual field tests of the materials while in use. Some of the larger companies have testing

departments, employing engineers whose duty it is to make tests of materials purchased and prepare specifications therefor. Such work results in the development of a group of standard articles or materials of particular quality which have been proved best adapted to the service imposed, and which are always specified by the purchasing agent when a new consignment is ordered.

Production Records

In accounting for the production of the property as a whole, and for individual wells, it is necessary to maintain a systematic record of daily production based on actual measurement of the quantities of oil and gas produced. Oil production is determined by gaging in cylindrical tanks

Daily Well Production Record
Well No. 16. Month of September, 1923.

Date		Gross Fluid, Barrels	Cut, %	Water Content, Barrels	Clean Oil, Barrels	Producing Time Hrs.	Min.	% of Total	Explanation of Idle Time
Sept.	1	112	8.	9	103.	23	30	97.9	Engine trouble
	2	120	6.	7.	113	24	0	100.0	-----------
	3	116.	10.	12.	104	23	0	95.8	Engine trouble
	4	54.	7	4	50.	14	40	61.1	Parted rods
	5	110.	6.	7.	103.	22	20	93.1	Full storage tank.
Totals		2940.		206	2734	Average		91.5.	

Fig. 347.—Typical form for daily well production record.

(see page 464), while gas production is measured by the use of various types of meters. The results are reported daily by the gagers on production records which will vary in form and arrangement with the practice at each individual property. On some properties, there will be facilities for accurately gaging the production of each individual well, but on many leases where individual well tanks are not provided, or where there is no means of temporarily segregating the production from individual wells, the daily production record will show but little more than the over-all production for the lease as a whole.

There must also be reported on the production record the Baumé gravity and percentage of water and suspended solids in the gaged fluid, data necessary in computing the "net oil" and its value (see Fig. 347). The production of water from each well is often separately recorded in order to disclose any unusual increase in water content which may be indicative of a condition requiring repair operations. A separate water record for each well is required by law in some states, notably in California.

The primary production record, taken as near the source as may be consistent with the facilities for gaging, is supplemented by the record

of oil run from storage into the purchaser's pipe line or other transportation facilities. At this point the oil is accurately gaged, and the "run tickets" issued by the gager representing the purchaser, furnish an excellent check on the primary records, after due allowance has been made for oil used on the lease, and for evaporation and other losses in gathering, dehydrating and storing. An intermediate check is afforded if the oil is also gaged as it flows into the main storage tanks, assuming that it has been previously gaged in small tanks near the wells.

Monthly Production Summary — *Month of September, 1923.*

Well Nº	Clean oil, Bbls.	Water, Bbls.	% of total time operating	Average Nº Bbls. Water per 24 hrs.	Average Nº Bbls. Oil per 24 hrs.	Remarks.
1	3016.	411.	98.2	13.9	102.4	----------------
2	2534.	292.	93.1	10.0	90.7	Three pulling jobs
3	506.	74.	32.0	7.7	52.7	Redrilling since Sept. 11
Totals	42,716	5,124.	96.5	11.0	92.2	

Summary of Oil Produced, Shipped and Retained in Storage

Carried in storage from August, 1923, Summary..	16,145.	
Production of clean oil during September, 1923..	42,716	
Total....................................		58,861 Bbls
Less lease consumption during September....	964.	
Less shipments during September............	53,422.	
		54,386 "
Carried in storage to October, 1923, Summary..........		4,475 Bbls

FIG. 348.—Typical form for monthly production summary.

Recording the production of gas is somewhat simpler than recording oil production, since there is no quality variable to consider. If the volume of production warrants, there may be a meter placed on the gas lead line from each well to furnish the individual well record, while a master meter provides the gross production for the property as a whole, at some point in the gathering system, before delivery is made to the purchaser's pipe line. Gas production is expressed in equivalent cubic feet or thousands of cubic feet at atmospheric pressure or at a "base pressure" a few ounces above atmospheric pressure. A record of actual flow pressures is convenient for many purposes, however, and is often provided by a regular series of pressure-gage readings incorporated as a part of the production record.

Graphic production records are often prepared from the tabulated production data better to display the variations in production in different periods. Individual well and property decline curves, in which production is plotted against time, are widely used in estimating future productivity and in oil property appraisals.

The production summary is compiled from daily reports submitted by the gager, and is tabulated in such a way that totals may be readily determined monthly (see Fig. 348). The marketed productions in barrels of oil and cubic feet of gas, multiplied by the unit selling prices, determine the monthly credit entries to be made under the sales accounts. Oil in storage is maintained under the production account at its cost value only, for if the marketing is deferred, its selling price will be uncertain.

Administrative Reports

In order that responsible officials and directors of the company may be informed on all aspects of the business, periodical reports must be prepared descriptive of the work of every department, together with a statement of the results secured. At regular intervals—usually annually—these reports must be reviewed and condensed for submission to the stockholders of the company, and for market reports that are given publicity in the financial and technical press.

To be effective, the system of administrative reports should reach down into every nook and corner of the organization. Every individual should be responsible to someone directly over him in authority, for a periodical report on work accomplished and the results thereof. Drillers prepare tour reports for their foreman, the latter, in turn, combines these with a report to the superintendent of development. The various superintendents report to the general superintendent or general manager, and the latter, in turn, reports to the president of the company. The president reports to the board of directors, and the board to the stockholders. Every department must be represented in the report system, but the development and production reports will naturally be of greatest importance. Table XLVII gives a list of reports covering every phase of the work of an ordinary oil-producing company.

The Annual Report.—Important among the list of administrative reports will be the annual report prepared for submission to the stockholders and general public. There is no uniformity to be observed in the form and substance of annual reports issued by various oil companies, but if we consider that their primary purpose is to supply the stockholder with such information as he may need to evaluate his stock, to gage the financial progress of the company, and to estimate its future dividend-earning capacity, it would appear that the report should contain the following features:

1. A frontis page, giving the name of the company, its principal place of business, the location of its properties, its capitalization and the number of shares outstanding, the date of the report and the names of the principal officers and directors.

2. A report by the president of the company, prepared as an introduction to the main body of the report, reviewing in a broad way the

TABLE XLVII.—LIST OF ADMINISTRATIVE REPORTS AND RECORDS FOR AN OIL-PRODUCING COMPANY

No.	Report or record	Frequency	By whom prepared	To whom sent
1	Driller's Tour Report	Tour	Every driller	Development foreman
2	Well Puller's Report	Tour	Each well-pulling gang boss	Production foreman
3	Well Pumper's Report	Tour	Every pumper	Production foreman
4	Roustabout's Daily Report	Tour	Each roustabout gang boss	Production foreman
5	Daily Power Plant Report	Tour	Each power plant engineer	Production foreman
6	Daily Dehydrating Plant Report	Daily	Dehydrating plant foreman	Foreman of transport and storage
7	Truck Driver's Daily Report	Daily	Each truck driver	Foreman of transport and storage and cost keeper
8	Shop Employee's Daily Report	Daily	Each shop employee	Shop foreman
9	Daily Report of Wells Drilling	Daily	Development foreman	Field superintendent and auditor
10	Daily Report of Operating Wells	Daily	Production foreman	Field superintendent and auditor
11	Daily Shop Report	Daily	Shop foreman	Field superintendent and auditor
12	Bi-weekly Power Report	Twice a month	Shop foreman	Field superintendent and auditor
13	Bi-weekly Construction and Repair Report	Twice a month	Production foreman	Field superintendent and auditor
14	Bi-weekly Drilling Report	Twice a month	Development foreman	Field superintendent and auditor
15	Bi-weekly Shop Report	Twice a month	Shop foreman	Field superintendent and auditor
16	Bi-weekly Engineering Department Report.	Twice a month	Resident Engineer	Field superintendent, auditor and chief engineer
17	Daily Oil and Gas Production Report	Daily	Gager	Foreman of transportation and storage, field superintendent and auditor
18	Run Tickets	Any time	Purchaser's gager	Production foreman, field superintendent and auditor
19	Monthly Production Summary	Monthly	Auditor	Production foreman, field superintendent and manager of production
20	Time Records	Daily	Department foreman	Time keeper
21	Labor Segregation Report	Daily	Time keeper	Cost keeper
22	Labor Distribution Report	Monthly	Time keeper	Field superintendent and department foremen
23	Distribution of Trucking Charges	Monthly	Cost keeper	Field superintendent and department foremen
24	Cost of Work Reports	Daily	Cost keeper	Field superintendent and department foremen
25	Departmental Cost Records	Monthly	Cost keeper	Field superintendent and department foremen

TABLE XLVII.—LIST OF ADMINISTRATIVE REPORTS AND RECORDS FOR AN OIL-PRODUCING COMPANY (*Continued*)

No.	Report or record	Frequency	By whom prepared	To whom sent
26	Pay-rolls.	Monthly	Paymaster	Auditor and treasurer
27	Pay-roll Summary.	Monthly	Paymaster	Field superintendent, auditor and treasurer
28	Pay Checks.	Monthly	Paymaster	Employees
29	Purchase Requisitions.	Any time	Storekeeper	Purchasing agent
30	Price Requests.	Any time	Purchasing agent	Outside merchants
31	Purchase Orders.	Any time	Purchasing agent	Outside merchants
32	Stores Received Report.	Any time	Storekeeper	Purchasing agent
33	Stores Requisitions.	Any time	Department foremen	Storekeeper
34	Stores Issued Report	Daily	Storekeeper	Cost keeper
35	Stores Issued Summary	Monthly	Storekeeper	Field superintendent, department foremen and auditor
36	Stores Inventories.	Quarterly	Storekeeper	Auditor, field superintendent and treasurer
37	Invoices and Bills.	Any time	Outside merchants	Purchasing agent, field superintendent, auditor and treasurer
38	Vouchers.	Any time	Auditor	Field superintendent and treasurer
39	Memorandum of Expenditures	Twice a month	Auditor	Field superintendent, manager of development and production, and treasurer
40	Journal Entries to Balance Ledger Accounts.	Monthly	Auditor to Secretary to	Secretary, or Auditor
41	Employment Ticket	Any time	Department foremen	Time keeper
42	Discharge Ticket	Any time	Department foremen	Timekeeper
43	Personnel Reports	Monthly	Department foremen	Personnel officer
44	Work Orders.	Any time	Any department foreman	Through field superintendent to any other department foreman
45	Monthly Progress Report	Monthly	Field superintendent	Manager of development and production, and president
46	Quarterly Progress Report	Quarterly	Manager of development and production	President and board of directors
47	Quarterly Financial Statement.	Quarterly	Treasurer	President and board of directors
48	Annual Report.	Annually	President, treasurer secretary, manager of development and production, chief engineer, field superintendent and auditor	Board of directors and stockholders

principal results of the previous year's work, with his interpretation of the financial outlook and the general condition of the company's affairs.

3. A balance sheet, in which the company's assets are compared with its liabilities, in the customary technical form. The balance sheet should be supplemented by a Profit and Loss Statement and an Appropriation Statement (see pages 625 and 626).

MIDVALE OIL COMPANY—BALANCE SHEET, JANUARY 1, 1923

Capital and Liabilities

Capital Liabilities:		
Authorized capital stock, 1,000,000 shares at $10 each	$10,000,000.00	
Less unsubscribed and unappropriated stock, 250,000 shares valued at	2,500,000.00	
Value of capital stock outstanding		$ 7,500,000.00
Ten year, 7% debentures (1921 issue)		1,000,000.00
Current Liabilities:		
Accounts payable	$ 29,874.18	
Loans and notes payable	6,816 36	
Accrued debenture interest	35,000.00	
		71,690.54
Reserve Liabilities:		
Surplus (see appropriation statement below)	$ 2,868,154.16	
Depreciation reserve	432,643.76	
Depletion reserve	948,230.89	
Income tax reserve	342,791.22	
Debenture sinking fund reserve	89,016 26	
		4,680,836.29
		$13,252,52.836

Property and Assets

Fixed Assets:		
Property, Plant and Equipment Assets:		
Lands and leases	$ 3,155,212.23	
Wells drilled	2,027,416 58	
Physical plant and equipment	1,496,112 07	
		$ 6,678,740.88
Inventory Assets:		
Supplies on hand and in transit	$ 329,263.87	
Oil in storage	227,196.32	
		556,460.19
Current Assets:		
Investments in securities	$ 5,081,710.57	
Accounts and notes receivable	32,093.82	
Rebate claims in adjustment	176.05	
American National Bank, San Francisco (cash)	816,492.54	
First National Bank, Petrolia (cash)	57,116 62	
Revolving funds	20,000.00	
		6,007,589.60
Deferred Assets:		
Prepaid insurance	$ 9,417.89	
Other accounts paid in advance	318.27	
		9,736.16
		$13,252,526.83

SUMMARY OF INCOME AND EXPENSE, YEAR ENDING JAN. 1, 1923

Operating Revenue:		
Oil sales	$ 5,294,316.22	
Gas sales	786,111.03	
Interest and dividends on investments	230,562.12	
Income from rentals	8,660.00	
Miscellaneous other income	17,658 74	
		$ 6,337,308.11
Operating Expenses:		
Labor	$ 1,992,016.60	
Supplies and equipment	635,699.19	
Power	64,228.84	
Miscellaneous other expense	628,442.21	
		3,320,386.84
Net operating profit		$ 3,016,921.27

APPROPRIATION STATEMENT, YEAR ENDING JAN. 1, 1923

Surplus from Jan. 1, 1922, appropriation statement		$ 1,963,425.16
Net operating profit for year 1922		3,016,921.27
		$ 4,980,346.43
Less:		
Interest paid on debentures and notes	$ 70,000.00	
Reserve for debenture sinking fund	89,016.26	
Reserve for depreciation of plant	147,279 84	
Reserve for depletion of property and wells	319,278.84	
Reserve for income tax	286,617 33	
Dividends paid	1,200,000 00	
		2,112,192.27
Surplus carried to balance sheet		$ 2,868,154.16

4. A report should be included by the general manager or superintendent in immediate charge of the company's properties. This report should be a technical report, dealing with the results of development and operation of the property, with conditions which have influenced the work of the year and with proposals for the conduct of operations during the immediate future, involving, perhaps, a discussion of new development work, additions to plant or changes in processes and methods. This report should be supplemented by a statistical summary of production obtained from the property during the year, together with maps showing the location of the company's properties and wells.

5. A report by the auditor gives cost statistics, together with data on the distribution of labor, supplies and general expense. The com-

pany's policy with respect to depreciation and depletion accounting should be fully explained, and the wasting assets should be periodically evaluated.

6. The annual report should also contain a statement by a licensed public accountant certifying to the accuracy and integrity of the financial data, more particularly, the accounts represented on the company's balance sheet.

Such an annual report would give the stockholder all information that he would need to keep fully informed on the financial condition of the company and the physical condition of its property. From it, he could compute, or at any rate closely estimate, the value of his proprietorship interest. Successive annual reports provide the only historical record of the company and its affairs, and their issuance has become an established custom in the financial world.

Quarterly Reports.—Dividends are usually distributed quarterly, and in order that the directorate of the company may be fully informed on the company's business affairs at such times, it is customary to prepare a quarterly technical and financial statement. The administrative reports prepared for this purpose are less formal, and are not ordinarily given publicity, though some companies permit brief summaries of them to appear in the technical and financial press.

Cost records, accounts and administrative reports gage the progress of the enterprise, and constitute the charts which point the way to future success. They are the common ground between the engineer and the financier, wherein the engineer may demonstrate to the man of business the worthiness of what he has created; wherein he may prove his right to leadership in industry.

A SELECTED BIBLIOGRAPHY ON THE SUBJECT MATTER OF CHAPTER XX

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SUBJECT INDEX

C

D

F

G

P

S

T

W

AUTHOR INDEX

(Finding list of authors referred to in the text and bibliographies.)